EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 109

DATE: Tuesday, February 18, 1992

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

FARR & ASSOCIATES REPORTING INC.

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EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, on Tuesday, the 18th day of February, 1992, commencing at 10:00 a.m.

VOLUME 109

B E F O R E :

THE HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

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D. COLBORNE	NIPIGON ABORIGINAL PEOPLES' ALLIANCE

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---Upon commencing at 10:00 a.m.

THE REGISTRAR: Please come to order. This hearing is now in session. Please be seated.

THE CHAIRMAN: Mr. Howard?

DR. ARTHUR RAYMOND EFFER,
CHARLES WILLIAM DAWSON,
JAMES RICHARD BURPEE,
GARY NEIL MEEHAN,
JOHN DOUGLAS SMITH,
AMIR SHALABY; Resumed.

DIRECT EXAMINATION BY MR. HOWARD (Cont'd):

Q. If you could first turn up 16B, overhead 16B of Exhibit 473, we will deal with the first informal undertaking.

Mr. Dawson, looking at that, and particularly options 6, 9 and 10 and the double asterisk, you will note at the bottom of the page where it's indicated it includes "Other", and I was so bold as to ask you what that meant yesterday. You said you would find out for us. Can you help with us that now?

MR. DAWSON: A. Yes. If we refer back to the previous overhead, which was 16A, in the cost model, under "Initial Capital" there, there were three categories.

There is Construction, Commissioning and Training, and what the footnote was meant to say was that, in fact, all those three categories are included

in that initial capital cost, whereas for the other options the commissioning and training were broken out separately for SCR. Under those options they have not been broken out separately and they are all combined in that one cost.

Q. Thank you. Now, Mr. Smith, yesterday we began to address the fuel issues that are relevant, the fossil option, and you told us that the four key factors were price and price forecasting, availability, deliverability, and characteristics of the fuel.

This morning I would like to address the pricing aspects of your work in a little more detail.

First of all, can you tell us what factors influence the fuel price forecasting which you do?

MR. SMITH: A. Yes. I guess the first thing I would say consistent with what I described yesterday is that any fuel we buy, any fossil fuel we buy, is comprised of the price of the actual commodity itself at the mine, or at the wellhead if it's oil, et cetera, plus any costs associated with transporting it or refining it and getting it to our generating station. So we really have two aspects to forecasting the price for Ontario Hydro.

The key factors in developing our

forecast are to examine things like current usage of the fuel by us and others, short- and long-term availability of the fuel, the cost structure of the industry we are dealing with, the general economic outlook, what kind of economic activity do we expect, particularly in Ontario but in North America, and to some extent to the effect that world economic factors influence a fuel such as oil.

We look at market conditions and any anticipated changes in those markets.

We look at competition between fuels and in the industry itself. For example, today I think natural gas prices are being very much driven by competition between the producers.

We look at the extent to which a fuel is a substitute for another fuel, gas for oil, for example.

We use our own experience in the marketplace as a major buyer of fuels, and we substitute that experience by expert advice. We will sometimes commission a consultant to look at a particular situation for us. We subscribe to reports that are produced by various agencies on a particular fuel or type of fuel.

The Fuels Division forecasts all the

costs, commodity and transportation associated with coal and nuclear fuel, which today represents 99 per cent of our fuel expenditure.

Q. What about natural gas and oil? Do you follow that as well?

A. There is a somewhat different process there.

The economics function of Ontario Hydro forecasts the commodity price for oil and gas, and then the Fuels Division applies specific information about delivery conditions, location of delivery, and the transportation system, and the utilization factors at the particular places to derive a delivered price to the station.

The forecast for oil by Ontario Hydro -- I described it as a macro economic forecast. I believe this was dealt with in detail by Mr. Rothman when he was here on Panel 1, and it has also been described in detail in an interrogatory filed, 8.9.1.

Essentially, just to capsulize it, they really look at general economic activity, both North American and global, they look at oil usage patterns and the sources of oil and the way that may change over time.

THE CHAIRMAN: If I may just interrupt

for a moment, that's the first reference that I noted of an interrogatory, and I suppose we now have to start the process that you are responsible for of putting down all the interrogatory numbers.

So could we have a new exhibit number, please?

THE REGISTRAR: No. 475, interrogatories.

THE CHAIRMAN: So 475.1 will be 8.9.1.

THE REGISTRAR: 8.9.1. Thank you, Mr. Chairman.

---EXHIBIT NO. 475.1: Interrogatory No. 8.9.1.

MR. HOWARD: I knew I would come to regret that.

Q. All right. Now, you have told us how we go about it, can you give us a few more details about how it is these economic modelling techniques are then used at Hydro?

MR. SMITH: A. Yes. I guess I was about to do a little bit of that.

We use the economic modelling techniques with judgment inputs to come up with forecasts. We also - I don't; the economics function of Hydro - subscribes to a number of other forecasting services to deal with economic forecasts including the forecast of oil.

Q. All right. Then can we come to the assumptions that were actually used in the Demand/Supply Plan, Exhibit 3?

A. Yes. I have an overhead up there, which is figure 14.6 from the Demand/Supply Plan. This just pictorially describes the forecast prices we had in 1989 dollars.

Q. Can you separate out the coal for example?

A. Yes. Starting at the bottom of the graph, the first line we see is for what we have called a high sulphur U.S. coal, and I noticed yesterday that Mr. Dawson called that a medium sulphur U.S. coal. It's terminology. It's a 2-1/2 per cent sulphur coal. That is about the highest sulphur coal we would purchase, but he's quite correct there are many higher sulphur coals in the marketplace.

That coal, as you can see, is forecast to be flat in real terms over quite a prolonged time period. That's a plentiful supply. There are large reserves of that coal and many producers.

The price is really a combination of two things. We believe that the real price of that coal will decline but it will be offset by real increases in transportation costs which are driven by oil prices.

Q. Then coming to what we have called low S U.S. coal?

A. Yes, that's what we call a low sulphur coal. It's under 1 per cent, it would be about .8 per cent sulphur, which we purchase today. We currently experience a premium for that coal because of its low sulphur. We are forecasting that that premium will increase for some period of time to approximately about a 20 per cent premium and then stay flat over time.

That is driven by the fact that we believe the U.S. Clean Air Act will make that a popular fuel in the United States and it will attract a premium. However, there is a limit that if that becomes too expensive then the alternative of installing scrubbers and going to a lower cost coal would come into play. So we think that that will dampen the price change on that coal.

The next line is Western Canadian Coal, which we currently purchase. Again, we forecast a fairly flat price on that. We have that in at a premium of about 40 per cent compared to our high sulphur U.S. coal, and that's largely driven by transportation - that coal has to be transported about 2,000 miles to our Nanticoke Generating Station - and

it is lower heat content than the coal in the United States. So the transportation factor, again it's like a double whammy. It is a long way to move it and you are moving less heat, and we don't believe it can get any lower than about a 40 per cent premium.

[10:12 a.m.]

THE CHAIRMAN: Do you have a figure for the sulphur content of that coal?

MR. SMITH: It is about .3 per cent sulphur, the coal we buy today.

THE CHAIRMAN: That is 0.3?

MR. SMITH: Yes.

The next two lines on the graph are natural gas and we have given an interruptible price and a price for what we have called a general service condition which tends to be a relatively high capacity factor usage of gas.

MR. HOWARD: Q. Would you just amplify what you mean by interruptible.

MR. SMITH: A. Yes. It is a gas service that from the gas industry, you cannot rely on it to be delivered at all times to you. You get a discount because of that. They have a right to interrupt it. We also view it as a gas supply which we do not have to commit to for any lengthy period of time, so it has a

value to us because our demand would be quite uncertain.

These gas prices that we built into the DSP were not site specific. They were just general indicators of price.

You can see that we had real price increases over time built into that forecast driven by, I guess, the general view then that natural gas prices would, in fact, track oil prices to some extent and that future gas supplies would be expensive to discover and develop.

And then the last line, the highest price line, is our forecast for light fuel oil to be used on our CTUs.

Q. All right. Light fuel oil as opposed to residual?

A. Residual fuel oil, yes. We haven't put a price forecast for residual fuel on there. It would have the same shape but be below the light fuel oil if we had it on. This is really diesel fuel.

Again, we have real price increases driven by the expectation over time that the world price for oil will go up in real terms.

Q. All right. Then in your view at the time of the Demand/Supply Plan in 1989, were you

satisfied that the fuel prices used were reasonable and flexible enough to deal with the options which are described in the plan?

A. Yes. We develop these. We also looked at a high price forecast and a low price forecast as well as our most likely forecast and examined all the options for sensitivity to those prices.

We also had our price forecast reviewed by external consultants and their view in general was that these prices were appropriate for examination of the options in the plan.

Q. All right. We know that in Exhibit 452, the 1992 update, there are some fuel prices revisited. Has anything changed in the update?

A. Yes. This next overhead again is a pictorial display of the prices. Now we are in 1991 dollars, but the most significant change is in the area of natural gas.

Q. Just before you go on, Mr. Smith, I notice not for the first time that in the DSP, they were 1989 dollars, but they were dollars per gigajoule and we now have '91 dollars per million btus.

How does that compute?

A. I can tell you how it arrives. I

guess the original graph, the one I previously had under the DSP was produced by, I guess, the people in charge of putting the plan together based on our information and their being faithful to the fact that Canada is a metric country now.

However, in my business, we tend to still relate to dollars per million btus and short tons and barrels of oil and pounds of uranium, and so my staff in putting this together did the usual thing and put it in millions of btus so I could understand it. The difference is about 5 per cent in price for all the various fuels.

Q. All right. And the relativity between them that we see will be still meaningful, will it?

A. Yes.

Q. All right. Now, where did this information come from?

A. Well, this is our latest forecast. We call it a 1991 fuel price forecast which was provided to system planning. It was attached to an interrogatory 8.2.18.

Q. Just pause for a minute. That would be Exhibit 475.2?

THE REGISTRAR: 475.2, yes.

---EXHIBIT NO. 475.2: Interrogatory No. 8.2.18.

MR. HOWARD: Q. All right. What are the significant changes? Can you summarize them for us.

MR. SMITH: A. The most significant change affects gas. Basically, all the other price forecasts are essentially the same with one proviso I should add, that in the two years since '89 to '91, in fact, there have been real declines in all the prices of all the fuels and so, we, in fact, reflect that.

You will see that in 1991 dollars, the prices still start at about the same place as they did when our forecast was in '89 dollars, so essentially, there has been no real change in price. In fact, there has been a decrease in price. So all of them are slightly lower because that.

Other than that, we are using the same price forecast, the same view of the world for coal and essentially the same view of the world for oil.

For gas, we have done a few things differently. We have lowered the overall price forecast, in the early years particularly, for the commodity. We have also tried to identify four different prices for natural gas; the first one being interruptible which is the same basic forecast for interruptible gas we had before.

We have also introduced different capacity factor usages because the price of gas delivered to a site is highly dependent on the utilization rate. And so, what we have done is identified for the price of gas at 100 per cent capacity factor, which essentially means that you use a specific amount of gas on a very steady rate every hour of the day essentially every hour of the year and that is the way you get the lowest possible price.

The next line is a 40 per cent capacity factor which means you are obviously not using it all the time at the same rate, and the difference in price there really represents the use of transportation and storage at less than the full utilization rates.

And then finally, the last price is a 10 per cent capacity factor price which really reflects that you are only utilizing the gas at a very low rate and which would be the kind of price we would have to live with for a firm gas supply to a peaking unit.

Q. Now, just before you leave that, interruptible is on the same basis, but the other three forecasts contemplate firm gas but at different levels of delivery?

A. That's correct.

Q. All right.

A. In the original DSP, we had sort of a general service category which did not capture the full range of price that you would experience for different facilities, so this is what we have done here. Basically what it does is it lowered the price for high factor gas, high load factor gas, compared to what we had in the DSP and raised it quite significantly for low load factor gas compared to what we had in the original DSP.

The overall gas price forecast, as I mentioned, is about the same as we had before, maybe just slightly lower in the early years but approaching the same price at the end of the forecast period.

I would point out that recently, there are forecasters who believe that is a very high price forecast and that there is a very real possibility of much lower gas prices in the future than those that we are forecasting. Part that is due to expectations of new technologies in the drillings that will reduce the cost of new discoveries, new concepts for gas such as coal bed methane, and recognition that the real growth for gas is as electric generation; and if that is the case, it probably isn't competing with oil. It is going to be competing with coal as a North American electricity generating alternative. So those

forecasters are forecasting lower gas prices.

Our forecast still reflects the former school of thinking that gas will be driven by oil and by high cost of future discoveries; however, we are aware of this potential for a lower price forecast and we will need to take that into account in decisions we make.

Q. How does this overhead S7 compare to what is figure 8-4 in the update Exhibit 452?

A. This figure was prepared to display just exactly what I have been talking about on the basis of different views of future prices of gas.

Q. When you say "this figure", so the record will indicate, you are looking at overhead SB which is a copy of figure 8-4 in Exhibit 452; is that correct?

A. It is S7.

Q. Sorry, 7.

A. S7B or--

Q. Yes.

A. --what do we call it up there saying?

Q. Right, S-7B.

A. S-7B, sorry, and it is a copy of something that was figure 8.4 in the update.

[10:25 a.m.]

Q. All right.

A. This is the commodity price of gas in Alberta as forecast by a number of different companies and consultants, and without going into a lot of detail you will see that there are a number of forecasts that show the real price increase over time, and you will see in the middle of the pack the Ontario Hydro forecast.

Q. All right. Just so people can understand, the ones that -- Ontario Hydro, we can understand and NEB, probably TCPL. TransCanada PipeLines?

A. That's correct.

Q. What's DRI?

A. DRI is Data Resources International. They are a consulting firm. They are one of the firms that our Economics function purchases forecasting services from.

Q. And CDN Enerdata?

A. Canadian Enerdata? That's a Canadian forecasting service that produces a forecast of various energy prices. Sproule is also a consultant in Calgary that produces forecasts of gas price.

Q. And then what's CGA?

A. The Canadian Gas Association.

Q. Is that different from Calgary Consultants? Is there a separate line for CGA?

A. Yes. I think the CGA one ends in the year 2000.

Q. Cowardly, eh?

A. Probably sensible. However, that's as far as they forecast it.

One of the comments we did have from our consultants' review of forecasts is that most of them don't go beyond the year 2000 in their forecasting and that they thought we were brave to go further than that.

However, the lower lines do reflect some of the newer forecasts that have been produced which do not project very significant changes in gas over time.

Canadian Gas Association is one. Calgary Consultants is basically a composite of forecasts produced by Calgary consultants, different Calgary consultants, and the other is a composite of the forecast of the Calgary banks.

Q. You mean, the Calgary banks all get together and pool their information, do I take it from that? Is that a published one?

A. No. They all produce individual forecasts.

This data was derived by a consultant who works for Ontario Hydro. We have used Little Engineering to advise us on gas supply for some time, and one of the things we asked him to do was have a look at what people were forecasting for gas prices on a broad basis. So this is really a graph that was derived from his report to us, and he has put a composite of the Calgary banks' forecast together.

Q. All right.

A. Sorry.

Q. Sorry. No, I interrupted.

A. So what it does is show that there is a difference of opinion about the commodity price of gas. It also shows where the Ontario Hydro gas price forecast fits within that.

The only other point I would make is that that commodity price forecast of Ontario Hydro's incorporated with delivery specifics is the basis for our gas price forecast that was on our previous exhibit. So they are consistent.

Q. We recognize that as a commodity price because it's identified as field gate?

A. Right.

Q. So no transportation?

A. That's correct.

Q. You also talked about availability in connection with all fuels. Can you help us about your predictions as to adequate reserves and first of all deal with coal?

A. Yes. This overhead basically displays the coals that we currently purchase. There are other coals. And without going into a lot of detail, what it does for each of the coals is indicate the reserves in billions of tons, the annual production also in billions of tons, and then the final column is a ratio of the reserve to the production rate measured in years.

Q. Taking the first one, Western Canadian, would you say on that analysis there is 175 years at current production rates?

A. Yes. And that's really --

Q. I don't think many of us will worry about --

A. That's really the point. The reserves are very extensive and very long-lived.

Q. What about natural gas?

A. I have a couple of overheads to talk about this, to elaborate on this subject.

Q. These are both S9 and S10, and they come from the DSP Update, Exhibit 472?

A. Yes. S9 is the equivalent to 8.3 in the Update and S10 is the equivalent of 8.1 in the Update.

In the original Demand/Supply Plan we talked about scarcity of economic natural gas and we were concerned about that. And I think it was because, among other things, the volumes of gas for electric generation potentially in North America were perceived to be quite a large and because when people talk about natural gas they generally talk about proven reserves being in the range of 10 to 20 years. What I hope to do with these next two overheads is put that in perspective.

What I have done here is I have got a 20 year outlook, I have got the current 1991 picture for North America, and then another one in the year 2010.

Q. Just before you start into the detail, where did this information come from?

A. Essentially, it's from a National Energy Board review of gas and oil and also the American Gas Institute reports, which we purchase. So it's derived from that.

What we have done again, to try and put this in perspective, in 1991 on the far left of the graph we are talking about total North American use of

natural gas, and it's measured in trillion cubic feet per year, and basically in the United States we see that it's 19 trillion cubic feet and Canadian usage is a little over 2 trillion cubic feet. In total, 21-1/2 trillion cubic feet.

The next much shorter bar is really how much gas is used for electric generation. You can see in the United States it's 3.7 trillion cubic feet but in Canada it's a very small amount, .1 trillion cubic feet or 100 billion cubic feet.

And then, we didn't do this to be cute, but there is a little line just barely above the zero line representing the Ontario use of gas for electric generation, and this includes Ontario Hydro and independent producers, and it represents .02 trillion cubic feet per year.

We then looked out at the year 2010. Same basic information. Total North American gas use has increased to 25.7 trillion cubic feet, and the gas for electric generation has increased to 7.3 trillion cubic feet. So most of the increases in the electric generation field, 3-1/2 trillion cubic feet, a 4 trillion increase.

We see that many people have talked about gas use in the United States doubling for electric

generation. This effectively reflects that, 3.7 going up to 7. In Canada we reflect it tripling but still only 300 billion cubic feet a year, and in Ontario we see it increasing by a factor of 10 but still only 200 billion cubic feet per year.

Q. That estimate in Ontario, I see on the left is Ontario electricity generation, and this is Ontario Hydro DSP?

A. Yes.

Q. Is there a difference between --

A. No, there isn't. It's poor labeling. If it hadn't been already filed we would have relabeled it and called it "Ontario Electric Generation", the same label as we have on the left.

Q. When you look at that tenfold increase you are including in that, not only Ontario Hydro and the DSP, but I guess, in a sense, the other generators who will be using gas? I guess to some extent they are in the DSP--

A. Yes.

Q. --in the non-utility generation plant?

A. That's right.

Q. But I thought we should clarify that. Then you go on to look at the next overhead, S10?

A. Yes. The next overhead, as we have said before, is figure 8.1 in the Update, and this really is trying to deal with the issue of proven reserves as opposed to very likely achievable reserves in the gas business.

And again on the left we have total reserves and at the very bottom there we have the proven reserves in the United States and Canada.

We have looked at reserves over a 20 year period as well, and the next bar is the demand for gas consistent with the previous chart.

Q. Just before you leave the left-hand side, you have got proven reserves that are something like 231?

A. Yes?

Q. Would you just describe what's included in U.S. potential, Canadian potential and Arctic?

A. Yes. Basically, based on geological information, there are very much implied, very large implied reserves of gas in the major gas areas of the gas producing regions of the United States and Canada, and the U.S. potential and the Canadian potential reflect the likelihood or the very much expected gas that's available as far as the industry is concerned.

I should also say that the U.S. potential has recognized the potential for the new enhanced drilling techniques to liberate more gas for each drilling activity that takes place than would have been produced in the past. It also recognizes more producibility from individual wells and it recognizes some coal bed methane.

The Canadian potential is basically the conventional type of reserve with not much allowance for enhanced drilling and no allowance for coal bed methane, but they are definitely reserves that the industry supports and expects to be there.

Finally, the Arctic reserves are obviously not producing yet, but they are reliably expected to be in the range shown there. So it adds up to quite a large amount of gas.

The next bar talks about the 20 year usage, cumulative usage, and you can see that adds up to about 470 trillion cubic feet, and as compared to measuring proven reserves and talking about having 10 to 20 years' supply, this ratio would indicate an excess of 50 years' supply and does not yet include some other potential developments for natural gas that could occur.

The final point I would make is that the

total cumulative use of gas that is consistent with our Demand/Supply Plan, including gas use for non-utility generation, is 3 trillion cubic feet over the next 20 years.

Having said all that, our view is that there will be adequate supplies of natural gas for the concepts that we have outlined in the Demand/Supply Plan and the Update.

Q. Then what about oil, to the extent it's relevant?

A. Well, we are not a large user of oil. And I will put that in perspective at the end of my comments.

But really, Canada's oil reserves, conventional oil reserves, are finite, but we also recognize frontier reserves and non-conventional reserves as being quite large. Their development will depend on price.

We are already importing a significant amount of Eastern Canada's oil supply from off shore, and we believe that will probably increase in the future.

For Hydro, we don't see a shortage of oil at all, and the critical factor for us is refinery capacity. Our projected needs represent about one per

cent of Ontario refinery capacity per year, so we really don't anticipate a problem in sourcing oil.

Q. All right. And then the third factor you mentioned was deliverability of all fuels. Did you identify any major problems about delivery that might be relevant to the Demand/Supply Plan, again starting with coal?

A. Yes. I would just make a brief comment on coal.

I put up some overheads that showed our delivery system today and I described the extent to which we use it. It is a well established delivery system. It's proven itself capable of delivering between 10 and 16 million tons a year of coal to us. It could easily be increased to deliver quite a bit more than that, and we believe that system can be kept in place to meet all the needs for coal that Ontario Hydro anticipates.

Q. What about natural gas?

A. Delivery of natural gas is highly dependent on pipelines.

[10:39 a.m.]

This overhead is an illustration of the pipeline system in North America. It shows the four major producing regions, one in Western Canada and

three in the United States, and a network of pipelines.

I don't need to get into a lot of detail here, but these are well established delivery systems and increasingly, we are making the connection to the U.S. pipeline system so that gas can be delivered into Canada or to Eastern Canada either through the Canadian gas system or through the U.S. gas system.

We believe this system is quite capable of being expanded to meet the needs of Ontario and the eastern parts of the United States. There is a lead time associated with it. It needs planning to identify your need and get in the queue, as it is, for reserving space on the pipelines and having pipelines expanded, but it can be done.

Q. Can you amplify, please, the lead times for the options we have been talking about?

A. Generally, the lead time on the pipeline system is two to three years, perhaps as much as four years.

This next overhead, S12, which is figure 15.6 from the DSP, shows the lead time for any of the facilities that we anticipate having. And with the exception of a CTU, all of the lead times would be consistent with arranging gas supply within the time frame of being able to build a facility.

The very short lead time CTU of two to five years, if, in fact, we could achieve the low end of that, would mean that we would have to run it on oil temporarily, but that is the plan anyway to dual fuel them, so we just don't anticipate that any prolonged delay in arranging gas supply, in fact, if we commit to a large-scale facility that will use gas, we will be able to get the gas supply in place before the facility is ready to use it.

Q. What about total Ontario situation?

A. Yes. I guess again we are just putting this in perspective. The current TransCanada system is capable of delivering 1-1/2 trillion cubic feet of gas to Ontario. It doesn't all stop at Ontario, but it currently delivers that much to the Ontario border. Ontario consumes about 800 billion cubic feet a year.

Recently, the pipeline - or it is undergoing expansion now - the latest approval by the National Energy Board will increase the capacity of that pipeline by 300 billion cubic feet that. That is in one construction phase for expansion of the pipeline.

As I mentioned in some of our previous discussion in overheads, the total gas use for

electricity generation, including that of NUGs, by the year 2010, we anticipate to be about 200 billion cubic feet. So it is a relatively small increase in the total transportation system over a prolonged period and we believe that can be accommodated.

We have one exception to our position on gas as compared to the original Thermal Cost Review and Demand/Supply Plan and that is, we do not believe that interruptible natural gas can be delivered at the time of winter peak which would be coincident with the gas system's winter peak.

There may be rare circumstances when it could be delivered, but the original plan assumed that interruptible gas would be available. We no longer assume that and we are planning on all of those facilities to be dual-fueled if we, in fact, put any in place.

Q. All right. And then what about lead times for oil?

A. Yes. Transportation of oil, and I am speaking of light fuel oil for CTUs as opposed to residual fuel oil, that is already an established system. That transportation will depend on the location of the plant and the needs of the plant. All the transportation methods could be used. Mr. Dawson

spoke of those too.

You can deliver by truck, which is what we currently do. You could design so that you could deliver by rail, pipeline or boat, depending on location; for instance, if you were near a refinery, you could hook a pipeline up and deliver directly.

We don't think that is a major problem because of the volumes we are talking about, but we would also build storage at the plant to overcome any potentials for interruption in delivery, but we do not believe that delivering the quantities we need is a problem.

Q. Okay. The final characteristic you mentioned as important is the fuel characteristics themselves.

Can you tell us something about how - I assume that relates to environmental considerations - how are they taken into account in the procurement of your fossil fuels?

A. Well, the main consideration is the fuel characteristics and how the consumption of the fuel affects the environmental aspects of the plant and the design of the plant.

The front-end environmental effects relate to mining, refining and transportation. These

are almost exclusively the responsibility of the supply industry. We recognize that the back-end impacts of utilizing fuel, such as waste products and airborne pollutants such as SO(2), are Hydro's responsibility and we have had extensive discussion of our methods of controlling those emissions.

Q. In general, does Hydro do anything with respect to what you have called the front-end environmental impacts of the production and transportation of fossil fuels?

A. Well, our first premise is that we don't want to duplicate the efforts that are made by others. The fuel industry or the energy industry is highly regulated and suppliers, to be in business, must meet all the regulations of their jurisdiction. We make compliance with their regulations, a term of our contracts, and if they weren't complying with regulations they would be shut down by their jurisdiction and we would cancel the contract.

But other than that we don't interfere in that side of the business and don't double up on the policing of what they do.

In many of our contracts, the price explicitly includes the costs of their meeting our environmental regulations and many of our contracts

have reopened our provisions such that if their environmental regulations change, we would negotiate a change in our price to accommodate their increased costs of meeting those regulations. We do that so that we are not a deterrent to their being environmentally responsible. If they can demonstrate that these are real cost changes, we will accept the price change.

Q. All right. Then what about what you have called the back-end products, ash and so on; how much flexibility do you have or do you permit in the procurement of fuels to limit the amount of these by-products?

A. Well, we have a fair bit of flexibility depending on price. The balance has to be struck between the price and on-site control. This overhead, which is figure 0.2.3 from the Thermal Cost Review, is an indication of the various coals, for example, that we can buy and their quality characteristics.

For us, the key environmental factors are ash, and you can see they vary from as low as 5 per cent to as high as 15 per cent.

Q. Where are you looking, on the second line?

A. I am looking at the second row under

ash.

Q. Yes.

A. We have described a cross there. I have picked the high and low which happens to all be under western sub-bituminous coal, but let me start with the first column under U.S. bituminous coal; ash can vary from 6 to 11 per cent, for example. Canadian bituminous, it is 10 to 14 per cent. And I have mentioned western sub-bituminous at 5 to 15 per cent. And finally, lignite has an ash content of 8 to 12 per cent.

The other key environmental is the last row under sulphur, and again, there is a range of sulphurs for each of the coals.

When we are sourcing, we can look at coals of that type and choose to purchase, for example, a low ash low sulphur coal, but it will have a price associated with it.

It may be more economic to purchase a somewhat higher sulphur coal and control the effects of the emissions at our site. What we do internally is make these decisions in an interactive way. The Fuels Division identifies the fuels that are available, the characteristics, the pricing. The planning part of the organization takes these into account in looking at the

options, as we have done in the Thermal Cost Review and the Update. And then once an option is selected, it is selected with some specifications for the type of fuel we would use and then we go out and buy the fuel that matches that specification.

The only other point I would add is that then limits some of your flexibility having set your plant up and designed it for a certain kind of fuel; however, there are things that the creative people at the generating stations can do if circumstances change and they need to go to a lower sulphur coal, for example. We have talked about putting flue gas conditioning on to allow us to use very low sulphur coal. And in that case, we need to be aware of the potential change and design our fuel supply program to, in fact, change the kind of coal we have bought, or coal or oil over time.

Q. All right. You have mentioned sulphur content is a major factor.

What about ash content; has it been a major factor in selection?

A. Well, it has always been a factor. Basically, it is implicit in the price we pay. When we buy fuel, we buy it on a delivered cost basis at the generating station. That is how we make the decision

as to what our lowest cost supply is.

So, high ash coal has lower heat content and generally costs more delivered to the generating station, so we do take it into account. Our basic objective is to buy as low an ash coal as we possibly can, consistent with the other quality needs.

However, recently, we are paying even more attention to the ash issue because disposal costs are going up, acceptable methods of disposal are disappearing and Hydro is, in fact, planning on trying to reuse or, in fact, sell most of the ash from our generating stations.

Q. Okay. Now, would you just discuss briefly your general strategy in procuring fuels for meeting the needs, both present and future?

A. Yes. Again, as we have talked about, the fossil generation needs are highly variable and we don't expect a change in that. We have to design our fuel supply strategy to meet the requirements, whatever they are. We do that by maintaining flexibility, looking at both short and long-term supply needs, trying to stay in the marketplace and be competitive and make sure that the fuels we purchase are from environmentally responsible suppliers and meet our environmental needs.

Basically, the only fuel that we are actively purchasing and see purchasing for some time in a big way is coal and our current strategy is to stay in the existing market, to be aware of alternatives. We have a portfolio of contracts that are short-term. Basically, we have three-year contracts that can be extended and renewed or cancelled as needed, and this seems to best serve our needs now to meet the variation and the changing quality needs and to stay competitive.

However, that situation can always change and we will continue to monitor the market to see if, in fact, there would be a need to make longer-term commitments for a particular kind of coal.

As far as natural gas, we have no identified plans to use natural gas in the short term with the possible exception of the Lennox Generating Station.

At this point, what we are doing is maintaining our knowledge of that industry, maintaining our contacts with that industry, making sure we keep up with developments in the industry so that we can be prepared to contract for supply ahead of time when we see the need; and if we really see a need developing, be prepared to have a very pro-active gas supply strategy, including possibly things like being out in

the industry, purchasing reserves or participating in the exploration or what have you. But at the moment, we have no identified need for gas and so we don't plan on doing anything further than that.

Basically, our situation for light fuel oil is the same. We don't see a major run-up in our need. We are currently handling that on an annual basis and we are unlikely to change that.

Q. Just to conclude, a review of the fuel issues, how would you summarize the fuel issues dealt with in the DSP and any changes which have occurred as a result of the update and are reflected in the update?

A. Basically, the issues are the same - price availability, deliverability and quality. The significant change, I think, has been our view of the future availability and possibly our view of the price of gas.

[10:55 a.m.]

Our current information suggests that gas will be available to meet any needs that Hydro has and any needs that the independent generation producers might have and that there will be sufficient gas available to deal with fuel switching programs.

We currently still have a fairly high

outlook for future gas prices, but we are aware that there are changes being contemplated by many forecasters, and we need to take that into account in our decision process.

Finally, interruptible gas, our view of that has changed, and we do not see it as a source of fuel for peaking units or a dependable source of fuel for peaking units and they would need to be dual fueled.

I guess I would say that at the moment we have no plans to build any new of façilities, and anytime when we do get to the point where we do need to do that the decision will then be based on our outlook for the various fuels at that time.

So, if in fact over the next few years our outlook for gas prices comes down, we will take another view of the combined-cycle option, for example, based on that kind of gas price forecast.

In conclusion, I would say that all our latest information suggests that fuel of all types will be available to us and that the basic prices are valid for comparison to the options.

Q. All right. Thank you, Mr. Smith.

Now, Dr. Effer, could we come back to you? We have had extensive description of the ten

options. Would you first describe for us how you would compare from an environmental point of view the fossil options which we have been discussing, the ten options?

DR. EFFER: A. The options and comparison of the options is not easy to do.

One basis for comparison that we have decided on is to calculate the emission rates of pollutants per unit of electricity produced, and therefore, emission rates are used wherever possible to compare.

We should bear in mind that in practice the actual environmental and health effects largely depend on plant size, location, proximity of local sensitive areas or populations and dispersion patterns for these emissions, and therefore, can only be assessed on a project-specific basis.

We have selected five different technologies from the ten options, and each of these technologies is to be compared with the environmental and health effects of what we call the base case, the four by 500-megawatt U.S. coal fossil plant with no FGD or SCR installed.

Q. Well, when you say that is the basis of comparison, what comparisons can be made?

A. There is a reasonable amount of data

on emissions rates of major components to air but incomplete data on other emissions, such as air toxics and some discharges to water, for example, and also solid waste.

So the incomplete data has to be supplemented by our opinions and opinions of others about the levels of emissions from the other options so that some comparisons can be made on the environmental and health effects.

Other environmental impacts, such as noise and land use, are very highly site dependent, so comparison between options is difficult and we have not emphasized them in this particular case.

Q. Have you got some data on the five technologies on which you have done these comparisons?

A. In overhead E9 --

Q. Before you go into it, where does this come from?

A. This source, Exhibit 35, is the Thermal Cost Review.

Q. All right.

A. This is a summary table of each selected technology with emission rates of sulphur dioxide, nitrogen oxides, carbon dioxides and solid wastes. More detailed comparisons of emission rates

will be discussed later.

One of the things I should draw attention to, particularly in this overhead, is that there is one error in the solid wastes. We have double counted the material that's produced to the FGD, and so that 95 figure is actually about 61.

The table also shows that there is a certain dating of this information. For example, we now know that the nitrogen oxides emissions from the CTU natural gas could be reduced somewhat by --

Q. Would that be option No. 5?

A. That is option No. 5, yes. It can be reduced with the use of technologies such as injection of steam.

Other general conclusions or general observations from this table is that burning of gas with or without pollution controls, and there you have options 5, 6, producing significant amounts of sulphur dioxide and solid waste.

And we can also note that where thermal efficiency improvements are achieved, such as in the case of No. 6, the IGCC, sulphur dioxides --

Q. Sorry, number -- you said No. 6?

A. Sorry, No. 9. Sorry. The sulphur dioxide and nitrogen oxides tend to be reduced, and, of

course, further reductions of NOx can be achieved with the selective catalytic reduction system. That's SCR.

Q. All right. Now, when you were originally discussing this you had the six issues, beginning with acid rain. Can you put this these emission figures in some kind of context with respect to those issues we discussed earlier?

A. If we look now at overhead E10, which is largely duplicating the information on the previous overhead and this is from Exhibit 468, that's the Health and Environmental Effects Report. We note that each of the five options will reduce the contribution to acid rain compared with the conventional coal-fired station option. That is in the first column. We are now looking at sulphur dioxide.

Option 2 is reduced by 90 per cent, CTU and combined cycle are virtually zero, and the IGCC is low, and the atmospheric fluidized bed combustion technique is reduced by 90 per cent also.

Q. Just as you went by that, I noticed that option 5, it says with water injection for NOx control, does that mean that the figure on the previous E9 has been corrected?

A. Well, it has not been corrected in the sense that we still carried over the dated

information from the Thermal Cost Review data onto this table.

But that is true, Mr. Howard. The figure for NOx can be reduced now with our knowledge of more recent technology.

Q. All right.

A. The scrubbers and SCR will effect major reductions in the emissions of acid gases, and all five generation options emit much less SO(2), ranges of 80 to 95 per cent, and nitrogen oxides 70 to 90 per cent with that technology, with that that we have mentioned just now.

The CTU and combined-cycle options would be negligible, as I previously said, and the result of this is that lower emission rates of sulphur dioxide would reduce ambient levels of SO(2) and sulphate aerosols, particularly in urbanized areas, and these levels have been shown to coincide with increased hospital admissions of asthmatics and other sensitive members of the population.

Q. Can we turn now to ozone, which I believe now is the second issue you have been discussing?

A. Yes. We can look at the same information that's shown in E10.

If we look at the nitrogen oxides that we have done for acid rain, you can see that the greatest reduction will be achieved by the IGCC option and by the combined-cycle option and the atmospheric fluidized bed option.

We have also mentioned that the content of the nitrogen oxides from the option, from the CTU option, can be brought down to a similar low level.

So reductions of nitrogen oxide of this high order will contribute to some reduction of ozone formation, but it's difficult to quantify without more specific information on the air shed to be affected.

The marked reduction of nitrogen oxide emission rates from each option would contribute to lowered ozone and smog levels in those situations where NOx and not volatile organic compounds, VOCs, is rate limiting.

These lower levels would contribute to reducing chronic health effects among sensitive members of the population and also reduce the effects of ozone-sensitive vegetation and materials.

I should also draw your attention on this to the limited information we have on VOCs and the information as shown in this table.

We believe that the emission rates of

volatile organic compounds from these other technologies is as low as the base case and that we don't believe that these technologies will act to increase ozone levels by producing more VOCs and emitting them to the atmosphere.

Q. I see CO(2) is on E10. What about the greenhouse effect?

A. The emission rates of carbon dioxide will be either decreased or increased slightly, depending on the option selected.

The emission rates are reduced significantly for the gas-fired options due to their high combustion efficiency and to the inherently low carbon content of the fuel.

The coal-burning IGCC option will produce slightly less CO(2) due to the higher efficiency of the energy conversion. However, the conventional coal-burning station will increase its CO(2) emissions slightly because 90 per cent of the CO(2) which is contained in the calcium carbonate scrubber, the limestone, will be released to the atmosphere by a reaction with sulphur dioxide.

In a similar way, carbon dioxide emission rates will be increased from the fluidized bed option, option 10, due to calcination of the fairly large

amounts of limestone used in trapping sulphur dioxide.

I should mention that the other greenhouse gas which has been associated with fossil future combustion, nitrous oxide, there is very little information on this, but the current data suggests that this is a very, very small amount relative to the amount of CO(2), and for present purposes we are ignoring it.

No direct health effects have been attributed to increased concentrations of CO(2). However, predicted climate changes associated with increased temperatures may affect human health, but to the extent, this effect cannot be measured without some far more detailed knowledge about factors such as temperatures, patterns of precipitation and climate details.

Q. What about the next issue, air toxics? How have you done that?

A. Although emission rates for air toxics have been characterized for the conventional coal-fired generating station there is not a great deal of detail on emission rates for these five options.

Turning to overhead E11, this is the data that's available first of all for inorganic compounds. This was derived from actual experimental data looking

at emissions from the Lakeview Generating Station and --

Q. Exhibit No. 4 is --

A. This is Exhibit No. 4. It's the Environmental Analysis.

So we have quite a comprehensive listing of air toxics in the flue gas from the Lakeview station.

Continuing with the next overhead, E12, and this is from the sources from the Environmental and Health Effects Report, Exhibit 468, we see a range of various organic compounds from the conventional coal-burning station.

This has been obtained from a number of sources and it is also available from many American sources, this kind of information. But, as I say, the data from the other five options is very sparse or even non-existent.

What we can say with reasonable confidence is that using natural gas as a fuel would probably result in the lowest emissions to the atmosphere of toxics.

We do know also that air toxics will be very likely reduced significantly by absorption during the gasifying step of the IGCC option and in the

sulphur dioxide scrubber at the conventional coal-burning option.

Additionally, the fluidized bed option, which would use baghouse filters, will achieve some absorption of air toxics onto the high particulate collection in the baghouses. We also believe that volatile organic materials may be absorbed on the material collected on these filters. But again, little firm data is available.

We believe, therefore, that there is plausibly no air toxics released with the gas-fired options. We expect significant reductions by the SO(2) scrubber and almost complete removal in the IGCC option and possibly good reduction of air toxics in the atmospheric fluidized bed option.

All options, therefore, will reduce the release of air toxics to varying degrees, and, therefore, reducing the contribution to adverse effects of air toxics on health.

The impacts of air toxics on human health is estimated in more detail in Exhibit 468 for a base case coal-fired option with no scrubbers and with no selective catalytic reductions.

Q. Then, what about discharges to water, is the next...

A. We have overhead E13, which is again taken from Exhibit 468, the Environmental and Health Report.

[11:15 a.m.]

We can get from this data that the gas-fired CTU option - that is No. 5 - will have no significant water use and, therefore, negligible discharges to water. However, if we do adopt this more recent control technology by steam or water injection to reduce NOx production, water use is increased along with some releases to water coming from the water treatment plant.

The coal-fired IGCC option, No. 9, will require only about half the cooling water requirements of the conventional coal-burning option. And except for the conventional steam cycle option, very little information is available about the inorganic and organic discharges to water.

What we do know about option 2 with the scrubbers is that the wet scrubbers will produce blowdown high and dissolved salts, and that matter has been quite an issue with us on the Lambton station.

The conventional coal option may also discharge slightly more heat to water due to its lower thermal efficiency associated again with the scrubber

operation. This is very small.

For those options having discharges to water, the actual effluent discharge rates of contaminants will largely depend on the in-plant control technologies. We have mentioned previously the ongoing MISA - that is the municipal industrial strategy for abatement - these initiatives will identify the appropriate design systems to control effluent discharges from the conventional steam cycle and this method of approach can quite readily be applied to these other options.

The ongoing MISA program will develop these systems for new plants also and as I think I have said before in my first presentation, this MISA program requirement is for a reduction and eventual "virtual elimination" of toxic contaminants.

So, as far as discharges to water, all options that discharge water will meet these new requirements and we believe that this pathway will result in much reduced toxic effects to human health.

Q. All right. Then solid wastes?

A. This over overhead, E14, is again from the Environmental and Health Report, Exhibit 468, and also includes the error that I pointed out in the previous table; that is, the 65 figure under option 2

should be 29; in other words, the limestone waste, the product from the scrubber, produces about as much weight as the coal ash.

What we can also see from here is that a CTU produces virtually no solid waste. The coal-fired option would produce approximately twice the amount of waste, as I have said, but this scrubber waste will be largely wallboard grey gypsum and we intend to utilize that for this purpose.

The amount of waste from the IGCC - that is under No. 9 - will be little changed; however, the ash form that is produced by that operation is more slag-like and is very much more acceptable for disposal or utilization than conventional flyash.

The effects of solid waste on human health are negligible for those options using natural gas as fuel.

The solid waste from the fluidized bed option - that is No. 10, the last column - it may be hazardous. It could be hazardous in the sense of immediately handling of the waste and I think Mr. Dawson mentioned this. You may recall that the limestone is converted to quick lime, calcium oxide, which when contacted with water could produce quite a strong exothermic reaction which would have to be

recognized.

Again, water discharges from such a waste would be high in dissolved solids and would have to be confined or suitably treated.

Q. You mentioned a few moments ago that there is an estimate in Exhibit 468 of the health effects of these options.

Can you describe briefly for us how they were evaluated?

A. Exhibit 468 adopts the recently recommended guidelines for human health risk assessment of the California Air Pollution Control Offices Association and the U.S. Environmental Protection Agency. The generally agreed opinion is that air toxics provide the main environmental pathway leading to human health effects, so the evaluation in Exhibit 468 was based on air toxics emissions from fossil fuel combustion.

Ground level concentrations of air toxics for the option 1, the highest toxics emitter of the various options - that is with no FGD or SCR - were calculated by using the MOE's proposed regulation models and we believe this is a worst case situation.

What we also did with this study was to take one whole year's meteorological data at the

Lambton site and also the population distribution in that Lambton area for the basis, the modelling exercise.

Cancer risks for air toxics were estimated by multiplying the predicted ambient air concentration by specific unit risk factors established for each toxic material and which in turn have been recommended by the U.S. EPA and California Department of Health Services. So the maximum cancer risks to an individual in total population were calculated for the inhalation exposures.

Q. Can you give us an example of this estimation of health effects?

A. On overhead E15 from the Exhibit 468, the health and environmental report, we show here a diagram showing the distribution of calculated risks around the generating station. It is not too clear here, but if you look at the intersection of the vertical 'O' and the horizontal zero, that is the location of the Lambton stack.

So, imagine on the left-hand side running along the isopleth, the left-hand isopleth, that is roughly tracking the St. Clair River and the predominant wind direction is in slightly in the north northeast to southwest direction.

The most impacted area as can be expected is within several kilometres of the station. That is about --

Q. How do we tell it is the most impacted area?

A. The isopleths, the two small isopleths marked E1E(6), 1E(6), are the calculated risks close to the station. The furthest isopleth or the additional isopleth is only a tenth of that level and --

Q. That is the one marked 7E7?

A. Yes.

Q. Okay.

A. So closer to the station, there are higher risks than depicted. If one goes into more detail, there are areas with slightly higher risks than the two isopleths marked 1E(6).

Under the worst case scenario, the estimated maximum risks to an individual is around two in 1 million, which implies that no more than two of 1 million people exposed to the maximum air toxics concentrations for 70 years would develop cancer.

Such health risks have been considered acceptable under the United States Environmental Protection Agency guidelines and is not much different

from typical daily life risks.

Q. Do we take from this that the population in the study area is actually going to receive that kind of extra risk?

A. No. The risk assessment is firstly used as a regulatory tool and the estimates don't provide actual risks; they provide a useful sense of the relative risks, but they are not a reliable indication of the absolute level of risks faced by people.

There are many uncertainties associated with risk calculations, such as the actual estimations of emissions, the dispersion calculations, various exposure assumptions such as the timing and the spacial distribution and other assumptions such as the dose effects relationship. And the International Joint Commission, the IJC, has recently cautioned that predicted cancer risk estimates should not be interpreted as actual risks to humans.

Q. What we have in E15 is air toxics.

Can you help us with exposure to other pollutants from the fossil fuel station?

A. Yes. We have concentrated on one pathway. There are several other pathways that would also contribute to overall risk estimation. These are

primary direct pathways and secondary or indirect pathways.

Other primary pathways include ingestion and dermal exposure. That is exposure through the skin. Secondary pathways include assimilation of a pollutant via one or more food chain pathways.

These estimates of risk via these pathways require much more site-specific information, such as deposition rates on crops, soils and surface waters and, of course, a lot of information on how much of these effected foods are used by local populations.

Most of this basic information is not available at the time and for that reason, we have only used the inhalation pathway currently to estimate risks.

For other pollutants such as sulphur dioxide, nitrogen oxides, ozone and acidic compounds, the adverse effects are mainly to the respiratory system. In Exhibit 468, we have calculated these health effects by comparing the model concentrations - that is the concentrations determined by use of standard models - with the regulatory criteria, and we have assumed that these regulatory criteria are a firm basis for, in most part, for protection of human health and in the fact that the limits to supply within those

criteria, we are concluding that the regulatory criteria can be met and that health effects are small.

Q. All right. Finally, Dr. Effer, can you help us pull together your conclusions with respect to the comparisons you have made of the fossil options?

A. The overhead E16, which is rather a busy table, is meant to summarize what we have found out by comparing the various options with the six environmental issues that we have been talking about. And very briefly, the use of scrubbers with the coal-burning option and the use of SCR technology throughout will markedly reduce the contribution to acid rain and ozone formation, and that is shown by running your eye down the acid rain column and the ozone column to see the actual reductions in a percentage basis from the base case.

So, we have essentially in the '90s, a reduction of sulphur dioxide and around 80 per cent of nitrogen oxide. So as I have said before, acid rain and ozone potential formation will be much reduced.

The small increases that we see in carbon dioxide emission rates between options will produce only very minor changes to the total CO(2) emissions from our generating system, but it is of interest that under some circumstances, the emission rates of carbon

dioxide will actually be decreased.

We believe all options will achieve marked reductions in air toxics either due to the inherently low level of toxic materials in the fuels used, particularly gas consumption, and the air toxics emissions will also be reduced by scrubbers and generally more efficient particulate control.

The reduced air toxics emissions to water will also be very marked and will have a reduced effect on human health.

We find that there are other comparisons between options for factors other than I have listed here and these can be found in Exhibit 4, which is the Environmental Analysis, and more detail is also available in Exhibit 468, the Environmental and Health Report.

MR. HOWARD: Thank you, Dr. Effer. We are turning to a new topic.

THE CHAIRMAN: We will take a 15-minute break.

THE REGISTRAR: Please come to order. This hearing will recess for 15 minutes.

---Recess at 11:34 a.m.

---On resuming at 11:53 a.m.

THE REGISTRAR: Please come to order.

This hearing is now in session. Be seated, please.

MR. HOWARD: Q. All right. Now, as advertised, Mr. Meehan, we are coming back to you, having dealt with construction and operations and costs of the ten fossil options.

Would you just tell us how, where the characteristics are so different, you, in planning, go about comparing the different options?

MR. MEEHAN: A. The best way that we know to compare the economics of different options in simple comparisons is to calculate the levelized unit energy cost or the LUEC that you heard about in Panel 3. Panel 3 discussed this topic extensively, I think.

Q. Yes, that was a long time ago. Could you remind us about LUECs?

A. First of all, we use it as a screening mechanism for planning purposes, and it is an internationally known or recognized method of making such comparisons. It is used in Europe and it is used in North America.

The LUEC is expressed in cents per kilowatthour and it takes into account all of the costs associated with an option over its lifetime. It's really the single value which best describes the option's total lifetime cost.

LUEC can be viewed as the price that one would have to charge for each unit of energy produced by a generating option over its entire lifetime to exactly recover the costs incurred over the life of that station.

Q. How are the different sizes and characteristics dealt with?

A. The LUEC puts the option on a -- options, rather, on a level playing field. It permits comparisons of costs among options with different sizes and lifetime cash flow patterns.

Q. And just remind us about the limitations when using LUECs to compare options?

A. Well, there are limitations. The options must have similar in-service dates, and they must be compared at the same annual capacity factor. If these features are different, then the comparison wouldn't be valid completely. It's most important that the capacity factors are the same in the comparison.

All options of the same component cost categories or divisions, which are capital, OM&A and fuel. However, the amount of the contribution of each of these divisions to the LUEC varies for different options, and we will see that in a minute or two. The contributions also vary for the same option at

different capacity factors.

Q. You have emphasized the importance of capacity factors. Could you just remind us back where we started yesterday about the definitions that are used for base, intermediate and peaking capacity factors?

A. Base-loaded stations are defined as those that would operate at 60 per cent or above in order to meet the 70 per cent average load factor I talked about yesterday, intermediate-loaded stations would be those that operate from 20 to 60 per cent annual capacity factor, and peak-loaded stations would be those that operate at less than 20 per cent capacity factor.

Q. In the material we have seen that there isn't that range. Generally how do you translate that?

A. We generally use a reference capacity factor for those three ranges, and so for peak we would use 10 per cent, intermediate we would use 40 per cent, and for base load we would use 80 per cent capacity factors.

Q. All right. Now, obviously it's important that the cost estimates are reasonable and technical feasibility. How do you go about assuring

yourself that those particular assumptions are reasonable?

A. Well, the approach we took is explained in chapter 0, pages 2 to 4 of the thermal cost review, which is Exhibit 35. But in summary, Hydro developed preliminary cost estimates for all the costs for the various components in the three cost divisions: capital, OM&A and fuel. Five external consultants were asked to review and comment on those preliminary estimates. Hydro then re-estimated the costs taking into account the consultants' review to produce the improved estimates.

Q. Did that end it there?

A. No. The consultant that had the overall responsibility to review and to coordinate reviewed the improved estimates as well as the preliminary estimates.

They found that the Thermal Cost Review methodology is sound. They found the capital estimates accurate and represent the most likely cost. They found the OM&A estimates were reasonable and complete and that the fuel prices had been well thought out and were based on sound methodology.

Q. And yesterday there were some particulars given from the Thermal Cost Update. Can

you just describe for us the extent of that update and how it was done?

A. Well, the Update first of all is part of a continuing process, as I mentioned yesterday.

What we have done is put all of the new cost information that we have and received in the last while through the mill once again to produce new LUECs.

Other members of this panel have indicated changes in the fuel price forecast and in the estimates of capital and OM&A costs. Some efficiency improvements have also occurred over the last two or three years.

Other changes have been made to reflect current forecasts of financial indices, such as escalation and discount factors. Although these changes have similar effect on the LUEC for all options they have different impact, depending on whether the option's LUEC is capital or annual cost intensive.

The LUECs for the Thermal Cost Review were expressed in 1989 dollars and in the Update they are expressed in 1991 dollars.

Q. When was this Update completed?

A. The Update of the thermal costs was completed in mid-January, 1992, this year, and the results are summarized in Exhibit 465.

Q. All right. Some of the changes have been discussed. Can you now summarize for us how the LUECs in that Update compare to those in the Thermal Cost Review?

A. This figure that's identified as M11 compares the LUEC for the TCR Report and the Update at the reference annual capacity factor of each option.

Q. Those are the same obviously for both, are they?

A. Yes.

Q. All right.

A. For example, option No. 1, which is the four by 800 megawatt conventional steam cycle burning U.S. coal, the Thermal Cost Review had a LUEC calculated at 80 per cent capacity factor of 4.2 and that, as a result of the Update, is 4.1 cents per kilowatthour. They are both adjusted to the 1991 cents per kilowatthour base.

Q. So if you look at then, it's fair to say that generally they are lower or very close to the same. What about operations 4 and 5? Would you comment on those, please?

A. The oil and gas-fueled CTUs at low capacity factors - that's options 4 and 5, that are both at 10 per cent capacity factor - have higher

costs, and this is attributable to the fuel cost component as well as a slight increase in capital cost and OM&A costs.

I believe the capital cost is increased two per cent, the OM&A increased almost 40 per cent as we heard yesterday, but the OM&A is a very small part of the total LUEC, and I will show you that in an overhead a little later.

Q. Can you tell us a little bit more about the elements in the CTU option that explain why they have gone against the general trend?

A. In Mr. Smith's evidence a short while ago, he referred to the oil forecast as being roughly the same, and, in fact, the difference between what was used in the '89 Demand/Supply or the Thermal Cost Review and what was used in the Update is slightly higher, particularly over the long term.

So some of this is the result of a higher, a slightly higher, about a 5 per cent higher oil forecast, and that and the capital cost and the OM&A costs that I referred to earlier is essentially the result of the higher costs shown for option 4.

Now, although the forecast price for natural gas is generally lower than what we used in 1989 we have found that interruptible gas for peaking

applications would not be available, and so we have treated the assumption with respect to how much oil and how much gas would be used in a 10 per cent capacity factor operation.

In other words, we have realized over the three-year period -- we have learned more about the gas business and the amount of oil that is used in option 5 is significantly higher now than it was in 1989, so even though we identify it here as a gas-fired CTU it has a 50 per cent oil fuel component at low capacity factors.

Q. It isn't here, but what about if it were used at high CTUs at high capacity factor?

A. At high capacity factor the gas-fired CTU would have a lower LUEC than in 1989 because we would be using a firm gas contract, as we assumed in 1989, but because the expected price is a little lower it is actually a little more attractive at high capacity factors.

Q. Perhaps I have already done it in a question, but can you safely draw any general conclusions about these options as a result of the Update, the costs?

A. I think you can draw the conclusion that very little has changed among all of those options

over the three-year period.

The changes in the resulting LUECs shown on that figure are within the ranges considered in the Thermal Cost Review.

Q. And then, has this Update changed the planning opinion with respect to the fossil options which are available for future development?

A. No, it hasn't changed our opinion. This overhead, identified as M12, shows the LUECs resulting from the Thermal Cost Update over the entire range of ACFs.

Now, this figure is similar to figure 14-21 on page 14-29 in the Demand/Supply Plan Report, which is Exhibit 3.

The updated results still indicate that we should consider either conventional steam cycle, option 1, with the FGD and the SCR, or the IGCC for base load applications.

Q. Now, you point out to us on the chart M12. Where we would find those and the numbers associated?

A. For base load applications you would look at the 80 per cent column which is on the far right of the figure.

Q. Right.

A. And you would see that the LUEC for option one is 4.1. If you go down near the bottom you will see that the LUEC for option 9 is 4.4. What I am suggesting is that those would indicate that both those options are suitable for base load applications.

Q. Then let's shift from that to the peak load applications.

A. In the peak load application if you look at the 10 per cent ACF column you will find that the CTU option on gas and oil, option number 5, which is suitable for peak load -- I should point out that the shaded areas on the figure represent the selected duty for these different options. So those which have shaded areas in the 10 and 20 per cent capacity factor range are those that we would pick for peaking duty.

Q. All right.

A. You can see that option 5 has a LUEC of 13.3. You can also see that option 7, which is a gas/oil combined cycle unit, has in fact a lower LUEC, and that is something that is developed in the -- in this review process that we have just come through.

In the 1989 work the option 7 LUEC was in fact higher than the option 5 LUEC, and it is because of our treatment of the fuel, the higher cost fuel and the additional efficiency that we gained through the

combined cycle that makes it attractive for peaking duty.

Mr. Dawson testified yesterday that combined cycle isn't as attractive as a CTU installation for peaking duty because it has a steam cycle; it has more things to get going if you want to make use of it.

So what this really means is that if we are in a position of needing peaking generation we would have to take a hard look at both the peaking CTU and the combined-cycle CTU installations.

Q. What about the intermediate range?

A. In the intermediate range there is no change in our preference there either. I think that we would find the combined cycle and the IGCC phased options both still attractive, and you will find them as being options 7 and 8. They're shown to have a LUEC of 7.

If you move up and look at the LUECs for options 2 and 3, both options 2 and 3 have a lower LUEC than option 7 and 8.

The order of this hasn't changed since 1989, that was the case, and we preferred the combined cycle or the -- and the phased IGCC to be more attractive than the options 2 and 3 at that time

because of the environmental benefits and because of the flexibility that you can get from options 7 and 8.

Q. You mentioned the three cost divisions and their relative contribution. Can we come to that now in the next overhead?

A. This overhead, M13, shows the relative importance of the three cost divisions to total lifetime LUECs.

Q. Just before you go on with that, I note at the bottom this is similar to figure 11-4-11 in the original Thermal Cost Review. What you have done here, I take it, is to update that with the new information as a result of the Update, is that correct?

A. That's exactly what we have done.

Q. Okay.

A. If I could carry across the first three circles at the top of the figure, option 1 is shown there to have fueling at the bottom of the pie. Fueling is attributed with 45 per cent of the total LUEC, capital is 41 per cent, and OM&A is 14 per cent. That's a relatively high capital content.

The other ones have higher capital contents in that line, option 9 and option 10. These are the IGCC and the AFBC options, and they have a lower fueling content.

In intermediate operation, the four that go across the page there, I draw your attention to option 6, which is the combined cycle, gas-fueled. The fueling cost there is 68 per cent of the total, and capital is 25 per cent; OM&A is only 7 per cent of the total LUEC.

In the peaking options, the option on oil, which is option 4 - this is just a straight, combustion turbine unit - the fueling is it 63 per cent of the total, the OM&A is small, and the capital is 33 per cent.

This is where I say that when the capital went up 2 per cent from what it was before, it was only operating on 33 per cent of the pie, and when the OM&A almost doubled in the review it was only operating on 3 per cent of the pie. A small increase in the fueling component, which is 63 per cent of the pie, has a big effect on that option.

Q. Can we think of that in another way? Is there another way of explaining the relative importance and the various roles?

[12:12 p.m.]

A. This figure M14 takes the information out of the table that was in M12 or takes some of the information out of the figure in M12 and it plots it.

Again, what I am trying to show here is that high capital cost options with low fueling price result in low LUECs at high annual capacity factors. That is shown on the right-hand side of the figure where the solid line with the triangles is the conventional steam cycle, and that would be 4.1 at 80 per cent capacity factor and it would be higher at lower capacity factors and the numbers are taken right off of M12. IGCC is a little bit above that and it is shown just as a solid line.

At the low end of the capacity factor, you can see where the combined cycle becomes attractive compared to the conventional steam cycle below 30 per cent capacity factor. In fact, at 10 per cent capacity factor, as I indicated, the combined cycle is now a lower LUEC than the combustion turbine unit.

Those two lines would actually cross over at about 5 per cent. So that if we saw the duty on a peaking installation to be 5 per cent or lower, the simple combustion turbine unit might be most attractive from a cost point of view.

Q. Thank you, Mr. Meehan.

I want to come now to what we have called "the alternative technologies", the alternative energy review, and Mr. Shalaby is finally going to have to go

to work.

First of all, on the subject of these alternative energy technologies, can you outline for us the planning studies on these technologies upon which the conclusions in the Demand/Supply Plan were based?

MR. SHALABY: A. Hydro has been involved in research and demonstration studies to do with alternative energy since the mid '70s. In the mid '80s, we conducted a planning review or a study of the potential of those alternatives and we documented that in Exhibit 57 which is entitled, "The Demand/Supply Option Study: The options." It is one of a series of documents that we relied on in the mid '80s to characterize various options.

That study looked at solar and wind and at wood, heat, much like what we looked at here. It also looked at cogeneration and small hydraulic options as well. It concluded that the use of waste for fueling electricity generating plants, whether it is wood waste or municipal waste, made some sense for Ontario.

It also concluded that cogeneration and small hydro have promise and large potential for Ontario and that in a big way became a reality since that time in the large potential for cogeneration that

we have seen developed since that time.

We also expected solar and wind to contribute in remote applications, remote communities and special niche market application.

We concluded that there is potential in some areas and that Hydro should continue to study and keep an eye on developments elsewhere in the world in different technologies and be prepared to take advantage when breakthroughs take place.

Q. All right. And what has happened since the mid '80s in that study?

A. Since that, we put together another study recently, and that is Exhibit 344, and we did that to be of assistance to this hearing and to this Board in putting together, in one document, a review of alternative energies that is maybe five or six years more current than the document that we filed before that.

The testimony that Dr. Effer and Mr. Dawson and myself will give on the subject of alternatives will be, in a large measure, based on that Exhibit 344. We obviously will not go in every detail in that exhibit. It is a 200-page exhibit. We will highlight what we feel is helpful at this stage.

Q. Why did you go about that process as

consolidated?

A. The reason we commissioned Report 344 really is that we had a large number of documents speaking about various technologies and various applications and the information was scattered, was not always consistent in its treatment of economics or of costing techniques, so we wanted to put it altogether and really, it had a 3C sort of mandate to it - to be comprehensive, to be consistent and to consolidate all the information that we have in Ontario Hydro about the subject. We documented all our assumptions about costs and performance.

We also wanted to know what the performance of these technologies might be in Ontario. A lot of the information on alternative technologies that is in the common literature and scientific literature would often refer to what the performance is in California, for example, or in Finland or places like that. We wanted to transport that experience to the extent we can into Ontario and make conclusions that are appropriate for Ontario.

One significant thing I would like to mention about the scope of studying alternatives is that we are studying alternatives characterizing their costs and environmental impacts in the context of them

making a small contribution to electricity generation in Ontario.

Really, we had very little contribution in areas like solar and wind today. We don't really know what the environmental impacts will be if a very large implementation of those options take place. So we are looking at it making a small contribution. We don't know what the impacts will be and the costs will be if a very large contribution takes place. So we are looking at the next slice of contribution and not half the electricity or anything like that made up of these options.

Q. All right. Would you just outline for us the options that are going to be covered, that are covered in more detail in Exhibit 344?

A. The options that I and Dr. Effer and Mr. Dawson will cover are solar, wind, fuel cells, biomass, which is wood and agricultural waste and further other materials, peat, and municipal solid waste. Those are the six options we will talk about.

Q. Okay. Are there any other alternatives that Hydro is aware of?

A. Yes, there are many other alternatives that discussion of the literature or technology studies would refer to as alternatives or

new energies or renewable technologies; for example, geothermal energy - tidal energy, ocean energy and wave energy. There are many forms of new conversion techniques of forms of energy that are out there that people are exploring.

We focused on those six because they offer a reasonable chance at being viable in Ontario. So things that we didn't think will be practical in Ontario we did not look at.

Q. All right. Then let's come to solar which you are going to deal with and I guess we should get your set of overheads marked as an exhibit, if that is appropriate.

THE REGISTRAR: The next exhibit, Mr. Chairman, is 476.

THE CHAIRMAN: Thank you.

---EXHIBIT NO. 476: Mr. Shalaby's overheads.

MR. HOWARD: Q. First of all, let's start in general, and tell me how the potential for solar energy was assessed. How did you go about it?

MR. SHALABY: A. Well, we started by looking at the solar resource and I guess in all of these alternatives we will talk about and describe what the resource is and then we will go on to describe what the technology to make electricity out of it is.

So we will start by the resource, and in the case of solar, the amount of solar energy that reaches any particular place on earth is really a function of the latitude of geography, where is it, how far away from the equator? The closer you are to the equator, the larger the solar energy.

It also is a function of the time and season - summer versus winter and so on. And to some extent, it is also a function of local atmospheric conditions - cloud cover, haze, that kind of thing. But in a very large way, it really is a function where you are in terms of latitude.

The way that solar energy is measured, it is measured as insolation and it is measured in units of megajoule per metre squared. And I would like to start referring to figure A1 in Exhibit 476. It shows a map of North America with solar energy indicated by contours or lines that would show megajoules per metre squared.

Q. So just looking at that, not surprisingly, if you take the highest number 20, it appears to be down in lower California, in Texas, and the lower states?

A. Yes.

Q. What is the lowest number we see --

well, 9 up in the Arctic?

A. Up in the Arctic. So again, you can see 8 even up in the North Pole out there, but it is really as we indicated, a function of latitude. The higher up you are, the lower the total energy falling. When you move further south and particularly southwest in the U.S., you get a higher intensity and a factor of one to two almost across the content there.

Q. Then can you describe for us the kinds of solar technology you will be describing?

A. Perhaps to use figure A2 in that exhibit to try and give a little bit of classification to the types of solar technologies. Again, it is just to help us put in context the technologies that we will talk about.

Generally, people would classify solar technologies into passive and active. Passive technologies would be things like architectural feature of a building, windows, insulation, landscaping, shading, things of that nature.

On the left-hand side, there is the active category and that is further divided into technologies that are termed solar heating, such as heating domestic water and space and swimming pools, and that will not be a subject of our discussion here.

We will focus on the blocked term "solar electric" which are technologies that make electricity out of solar power.

Finally, now that we came to solar electric, that is generally put into two compartments: One is photovoltaics and the other one is solar thermal. Those are the two options that we will be discussing in some detail here.

Q. Okay. Would you just then describe those two types of technologies and how they work?

A. All right. Photovoltaic technology is familiar to us; that is, some calculators operate using photovoltaic cells. They convert light into electricity. I was about to say solar energy, but most of the calculators would use Ontario Hydro light to convert it into electricity again.

Q. It is a reconversion of electricity into electricity?

A. It is. So, that is photovoltaics. They are semi-conductors made of various materials and the energy falling on the semi-conductor would cause electrons to flow in an outside circuit, usually in direct current feature.

To use photovoltaics in applications in the home, you would probably need converters to convert

that direct current to an alternating current and condition it, and this auxiliary equipment is usually called the balance of plant. So the module is called the photovoltaic module and then there is a balance of plant to make that into useable electricity. That in a nutshell is what photovoltaics are about.

Q. Okay. And solar thermal?

A. Solar thermal comes in various configurations, such as dishes, very much like a television satellite light dish, lined up with mirrors, would focus the solar rays falling onto it into an area in the middle, in the focus that would be very much heated and a fluid will be converted to steam and from there it into a heat engine to make electricity. That is one configuration.

Others would be a trough; a long concave trough with a tube in the middle that would contain a fluid as well that becomes heated from the concentration of sun rays.

Other formats in use in places in the world are called "solar ponds". A pond is where salt water would have various densities in a pond and that is used to store solar energy and used in a heat engine as well.

So those are various ways of converting

electricity in a solar thermal capability and we expand on that in our exhibit, if that subject is of interest.

The technologies generally are collectors and storage devices that heat a working fluid and that becomes a fluid that generates electricity in a heat engine.

Q. Okay. Can you give us some idea about how photovoltaics contribute to generation today?

A. The dominant application in electricity generation today from photovoltaics is in remote communities and in special applications, such as telecommunication repeater towers or navigation buoys that are very remote and they charge batteries and keep their buoys operating or lighthouses, for example. There are all kinds of monitoring equipment: air quality monitors, water level monitors that use photovoltaic facilities to charge batteries and operate their facility.

To give you an indication of the size of the industry world-wide, there has been sales of something like 15 megawatts of photovoltaics in 1990, so it is a large industry. Most of that goes into toys and calculators, but a considerable amount goes into utility applications as well.

Utilities come into the photovoltaic

business in demonstrating the operation of photovoltaics. Various utilities in the United States have large demonstration projects. Japan also has large demonstration projects. Here in Ontario, we demonstrated photovoltaics in an air quality monitor near Atikokan and that operated in the early '80s. It took samples of air quality in the area and telemetered that to head office for analysis.

We also operate - we meaning Ontario Hydro - designed and operated the largest photovoltaic facility in Canada, and that is in the northern community of Big Trout Lake. That facility is 10 kilowatt in size and it has been operating since the mid '80s.

We participated as well in residential photovoltaic demonstrations both at the Cortwright Centre and in a northern community called Long Dog Lake in 1990. So, Ontario Hydro has had experience over the last ten years or so in photovoltaic demonstrations.

Q. All right. And then solar thermal, how is that technology being contributing to generation?

A. Most of the solar thermal facilities in the world that are making electricity today are in Southern California. In the Mojave Desert, there's 350

megawatts of parabolic mirrors or troughs, parabolic troughs producing electricity into the southern California Edison system. That, by far, is the largest solar thermal activity in the world.

Southern California also has a concept called "solar towers" which is a field of mirrors and we have a picture of it in Exhibit 344. It focuses the sun rays on a high tower and the heat would work a fluid, whether it is water or molten salt, and generates electricity. It was termed Solar One and it operated in the early '80s and there are plans now to retrofit that with different working fluids and it will be called Solar Two.

There is also solar ponds operating in Israel, in the Dead Sea. I think they are exploring the high salinity in the Dead Sea to generate electricity.

So that is the world-wide kind of experience that we know of. There are no solar thermal facilities in Canada or in Ontario that we know of.

Q. How are the solar technologies applicable or suited to Ontario?

A. The nature of solar insulation or energy falling in Ontario is such that it is not direct solar energy. It is diffused. There's a lot of

diffused energy and that makes photovoltaics more suitable be than solar thermal electric, and I think that applies to much of Canada; that photovoltaics is really the technology of most compatibility in the climate. Because of the price and the nature of the technology, it is most suited in the rural communities today in niche applications and communications. That is the suited application in Ontario as well at this time.

The costs of producing electricity from photovoltaics is high today. We expect it to decline considerably over the next several years and we will show you our assumptions and costs a bit later on.

Another factor that we have to take account of in photovoltaics is intermittent nature of photovoltaic operation. You only get electricity when the sun is shining or when it is not cloudy and that has to be taken into account in evaluating and designing a photovoltaic facility.

[12:30 p.m.]

Other observations to do with the suitability of photovoltaics in Ontario have to do with the match between that resource and the need for electricity.

Obviously, applications that need

electricity during the daytime and the summertime would be one matched to the photovoltaic technology, applications such as air-conditioning or swimming pool heating, for example, although photovoltaics is not used for that purpose.

Municipal utilities in Ontario, many of them are summer peaking and they could find a good match between photovoltaic application and reducing demand on their systems in the summertime, but in general, Ontario as a whole is winter peaking, and, therefore, there isn't a perfect match between photovoltaic energy and winter peak.

To sum up, then, I think Ontario has potential for photovoltaic applications, but the biggest obstacle today is the high cost, and as those costs decline we will see more and more applications.

Q. You mentioned the potential for reducing cost. What kind of development is anticipated that will lead to that better cost performance?

A. There are two fronts that would lead to improved performance and lower costs. One of them is the quest to increase efficiency.

Increasing efficiency can come about by improving the design of the solar photovoltaic panel, the way the wells are made, the way the layout of the

panel is done, the glass, and so on, the way the panel is done and designed. The types of materials that are used for photovoltaic cells can also lead to considerable improvements in efficiency.

Once efficiency is increased, then the cost of electricity from the facility is reduced.

The other front is in manufacturing methods, ways of manufacturing those cells and large scale commercialization. It's really a chicken and egg problem here. If you have a large market, the price will eventually drop. Manufacturing methods that can reduce costs can also contribute significantly.

The balance of system that I spoke of earlier, the part that would take the direct current of electricity, convert it into alternating current and conditions it is a considerable cost, and improvements here can help the application of photovoltaics as well.

So those are the areas that can lead to performance and cost improvements.

Q. What particular kinds of photovoltaic did you look at in more detail?

A. For the purpose of the review that we conducted we nominated really two options to characterize and cost out and describe to you, and those are a 2 kilowatt option for residential

application. We envisaged a roof-mounted photovoltaic facility on a south facing side of a house to meet a proportion of the electricity requirements in a house. We also looked at a 100 hundred kilowatt photovoltaic option, also roof-mounted, on a large commercial or industrial application, a shopping centre or small manufacturing concern.

Q. Can you show us --

A. We have schematics of what that might look like in our exhibit.

Q. Can you show us the major assumptions and the cost results?

A. Turn to page A3 in Exhibit 476 to put some of those assumptions to you.

The two options are shown, their size, 2 kilowatts and 100 kilowatts. The two major assumptions we are making here is one on life for photovoltaics, and for the purpose of costing we assumed a 30-year life. It really is a judgmental call at this time because our experience is limited in that area.

The other major assumption is the capacity factor, how much electricity would one get from a photovoltaic facility in Ontario, and we indicate here 12 per cent capacity factor, and that is based on the experience we have with the various

photovoltaic facilities that we have operated over the years.

So those are the major assumptions, life and capacity factor, and they are shown in that exhibit.

Q. In that table the annual energy production is a result principally of those two assumptions?

A. That is correct, of the size and capacity factor.

Q. What are the major cost components?

A. The major cost components in a photovoltaic facility is the initial cost of manufacturing and installing that facility. We assume there is very little cost once that facility is installed in terms of maintenance or operations or -- of course, no fuel costs either.

So really the bulk of the cost is up front in installing the unit, and for the purposes of our analysis we assumed the costs would be about $4,000 per kilowatt in 1991, and because we expect that cost to go down considerably over the next several years we also characterize what the costs would be in the year 2000, assuming a reduction down to $1,300 per kilowatt.

So we expect the cost to come down from

4,000 to $1,300 over the next eight years.

Q. Those cost components are in figures 1, 10-4 and 10-5 in the review, Exhibit 344. I guess we will come to the LUECs in due course, will we?

A. Yes. We will describe the cost/benefit and LUECs of these options we go on.

Q. Then what about the wind resource? How is that characterized?

A. The wind resource is a function of wind speeds, turbulence, air density, and there are maps that show the general layout of wind resource in different parts of the world.

We are showing one here for Ontario, page A4. It shows wind speeds in kilometres per hour. I wish the lakes were shaded a bit so we could see the province a little clearer.

To my horror as well I see it described as Southern Ontario and I wonder whether Ms. Mackesy will take me to a definition of Southern Ontario again. This is a little bigger Southern Ontario than we usually talk about.

We see that the windy parts of Ontario are along the shores of the Great Lakes, 17-1/2 kilometre per hour speeds there, and there is a little donut-shaped wind speed sort of contour showing 20

around the Sudbury area. Sudbury is one of the windiest locations that we know of in Ontario as well.

Q. Too bad it doesn't go over to Winnipeg.

A. No, it didn't.

Now, these maps are of some general indication of what the wind conditions are, but they are of limited use because wind conditions are very local. There may be very windy conditions in some localized pocket somewhere where you have the topography and so on that would help in high wind conditions.

This is collected from weather data at airports and things of that nature, so it gives a first cut but it doesn't give the accurate information that wind resource developers would rely on.

They typically would measure the wind at a specific site for several months, they would look at wind speed distributions, and it's a very, very site-specific activity that has to be done for a specific site.

So that gives us a general idea but not good enough for wind resource assessment.

To give you a flavour of what a site-specific assessment might look like, maybe you can

turn to page A5 which has an indication of wind speeds at the Fort Severn, which is Ontario's most northern community on the shores of Hudson Bay, and below that a wind speed distribution for Cortwright, and the Board has visited the Cortwright Centre and has seen the wind turbines in there.

Those two diagrams show how variable the wind speed can be from one day to another and from one season to another. It also shows Fort Severn to be a higher wind regime. The average wind speeds there are about six or seven metres per second; at Cortwright they rarely exceed five or six metres per second.

Wind developers usually designate good wind resources to be about eight or nine metres per second. So neither of these two is really an excellent wind resource when it comes to making electricity.

Q. Can you now come to the technologies that are presently existing?

A. Again, similar to solar we will try and give a quick classification of what we called Wind Energy Conversion Systems, WECS, W-E-C-S, and figure A6 shows a little bit of classification here.

We start by showing that wind can be used for mechanical power, such as pumping water or for making electricity, and in the making of electricity

there are two broad categories of technology. One is a horizontal axis machine and one is a vertical axis, the egg beater type machine, and both of them were at Cortwright displayed for the public.

They come in various sizes and different blade arrangements and types, and so on, but that's the major category of technology that we will be speaking about.

Q. Can you just briefly describe how electricity is produced from these technologies?

A. Electricity is produced through a conversion of the kinetic energy of the wind by aerodynamic forces. Those aerodynamic forces would be transported to rotate a shaft that would drive a generator to make electricity. So it's really blades that operate through lift and drag and other aerodynamics to convert the kinetic energy to rotate the shaft.

The critical parameter here is what they call the swept area, the area that the blades would sweep to capture the wind.

We have talked about wind speeds or the wind regime as being a sensitive parameter, and the reason it's very sensitive is that the power produced in a wind turbine is a function of the cube of the wind

speed.

So, for example, the same wind turbine would produce about three times as much electricity in nine metres per second as it would in six metres per second. So when we go from six to nine while the difference may appear slight you produce 300 per cent more electricity at nine metres per second, very, very sensitive to wind speed.

The operating efficiency of wind turbines is about 40 per cent; the theoretical maximum is about 60 per cent. But most good turbines today would convert 40 per cent of the wind energy.

The industry has developed over the '80s and in the early '90s. Most wind turbines today have a swept area, blades that are about 20 to 30 metres in diameter connected to generators that are about 300 to 500 kilowatts in size.

There were larger developments in the late '70s and early '80s, 3 and 4 megawatt type of turbines. Quebec has one. The United States has two or three. Germany and Sweden have one each or so.

Those didn't work out. The mega project on the wind turbine industry did not work out, and really an intermediate size that is in the 300 to 500 kilowatts proved to be the most usable in the United

States.

Q. Can you give us a picture, then, of how widely wind conversion systems are used today?

A. The largest installations are in California, and I guess that was highlighted recently in places like Time magazine and other literature as well.

California has something like 14,000 or 15,000 wind turbines and installed capacity around 1,300 to 1,400 megawatts, which is a considerable amount of generating capacity.

Denmark comes second at about 2,400 turbines and about 200 megawatts. Denmark is a large manufacturer of the wind turbines as well. Many of the machines in the United States are made in Denmark.

The wind provides about 1 per cent of California's electricity, so a large installation is starting to make a contribution to California's energy, 1 per cent of their electricity.

In Denmark about 2 per cent of their electricity comes from wind.

Other countries have smaller installations, but there are many, many countries that are starting to see applications as well.

Q. What about the experience in Canada?

A. The Canadian experience spans two decades or more. It was really started by the National Research Council doing a lot of work on vertical axis machines, the egg beater type machines.

To date, there is something like 7-1/2 megawatts of installed capacity in Canada. Half of that is in a single machine in Quebec, a 4 megawatt machine in Quebec, and the details of the installations are in our exhibit. Figure 2-4-3 would list the significant wind generation facilities in Canada.

There are two test sites operated or funded by Energy, Mines and Resources, one in Prince Edward Island and one in Alberta.

We are starting to see wind farm developments. Wind farm is a place where you have more than one turbine, and there are pictures in our exhibit of wind farms.

Alberta and Saskatchewan have started to request proposals for wind farms. Alberta is a little further ahead than Saskatchewan in that regard. A community called Pincher Creek is starting to solicit up to 9 megawatts of wind farm activity.

So that's sort of Canadian experience in general.

Ontario Hydro demonstrated a wind/diesel

hybrid. We looked at a special niche of that market, and that is how wind turbines can assist diesel generators in remote communities in the North. And we demonstrated that in Sudbury in the early '80s and at Fort Severn in the late '80s, and we contributed to some extent to the Cortwright Centre facilities that you have seen as well.

Q. Then, what do you envisage as the role for wind energy conversion in Ontario?

A. We continue to see wind contributing to remote applications where electricity is expensive, such as remote communities in the North where diesel is the predominant way of making electricity. Some remote colleges may find small wind turbines to be economic and suitable for their purposes.

There are many applications now for pumping, water pumping, even in Southern Ontario. If it's in the middle of a farm where no electricity poles are available, a wind turbine will do the job, and many other remote applications like that.

The widest spread of electricity generation from wind really hinges on identification of good sites, so it really is a matter of finding a good site.

A good site in California is

characterized by good wind speed. High on the agenda is a good wind speed regime, it also usually it's close to transmission lines. If you have a good site that is 100 or 200 miles away from transmission lines, then the costs of bringing the electricity in would outweigh the benefits of the good site.

The land has to be available for wind developments. For example, while the shores of the Great Lakes are windy I don't know to what extent those lands would be available for wind farm developments. So if the price of the land is right and it's available for development, close to transmission, if we can identify enough sites like that there will be more widespread wind generation in Ontario.

The intermittent nature of that resource is also a factor to be considered in operations and planning.

Q. Can you just outline for us the likely developments you see?

A. Well, the developments that would lead to better performance in wind and reduction in cost will focus more and more into advance design of the turbines and the blades, the control systems.

The industry, as I indicated, has come a long way during the '80s. They have explored already

improvements to do with siting the wind turbines relative to one another on a farm. Maintenance practices and operating practices, all of those have been tuned quite well now, and operators know how to gain a lot of wind energy from their own farms at this time, but further developments in turbine design and control systems...

Again, the issue of large scale commercialization; the bigger the market the lower the product price will be.

There is a new operating regime being explored by one of the companies in the United States, something called variable speed operation. Most of the wind turbines today operate at a fixed speed. They are trying to develop a turbine that would operate at various speeds and that could capture more of the wind energy more of the time and can lead to a significant improvement in economics.

[12:53 p.m.]

The challenge to the industry really is designing a turbine that would be suitable for moderate winds speeds, low wind speeds. I think the industry knows now how to capture wind energy in a good wind site, but there are many, many more moderate wind sights and if they can crack that market, the wind

energy can take off quite nicely.

Q. Okay then, what specific options did you look at in the study, Exhibit 344?

A. We looked at two options: One is a 10-kilowatt single wind turbine, very much similar to the one you saw at Cortwright, enough to power a residential or farm application; and the other one is a small wind farm, 20 units, each of them rated at 350 kilowatts. So we used those two as representative of the potential wind developments in Ontario.

Q. All right. Again, would you just outline for us and refer to us the assumptions about performance of these two alternatives?

A. The assumptions we used - first of all, about the wind regime, we assumed a Sudbury-like wind regime, something like 20 kilometre per hour wind regime, and that is, again, amongst the best in Ontario, as I mentioned.

And then in terms of cost and life, if we turn to page A-7 in Exhibit 476, again, the two critical assumptions are the useful life of the wind turbine and the annual capacity factor. The annual capacity factor is based on our experience in Ontario with wind turbines, 22 per cent capacity factor, and the annual energy production is a result of that.

The other significant assumption is a 25-year life. It is a judgment call at this time. In practice really, wind developers keep replacing various parts of the wind turbine along the way. They replace the blades; they replace the control systems, the brakes, and so many parts of the turbine keep changing over time. So, the assumption on life is really to calculate costs for our purposes here.

MR. HOWARD: All right. Thank you.

Mr. Chairman, we are coming to fuel cells.

Would this be a good time to break?

THE CHAIRMAN: Yes. We will break now until 2:30.

THE REGISTRAR: Please come to order. This hearing will adjourn until 2:30.

---Luncheon recess at 12:56 p.m.

---On resuming at 2:30 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Please be seated.

---Off the record discussion.

THE CHAIRMAN: Now that we are in the mood for announcements, I will say that we are going to stop today at a quarter to five and we will not, not sit tomorrow afternoon because of an intervening event.

So, we will have to stop at one o'clock tomorrow. Thank you.

MR. HOWARD: I think that is probably a more welcome announcement than mine. [Laughter]

Q. Mr. Shalaby, coming now to fuel cells, if we can, can you tell us what fuel cells are?

MR. SHALABY: A. This is a challenging after lunch period here. I have got to keep it exciting.

Fuel cells are devices that convert the chemical energy in the fuel directly into electricity via an electrochemical process. In a way it has similarities to a battery. It has an anode and a cathode and an electrolyte, but unlike a battery, you have to keep feeding it all the time. A battery has all it needs to produce electricity for a limited period of time. A fuel cell would need to be fed continuously to produce electricity.

If I can prefer to figure A-8 in the package, Exhibit 476, it would show a schematic diagram of a fuel cell power plant and it shows at the left-hand side of the diagram something called "a fuel processor" and that is used to convert a fuel like natural gas or naptha to a hydrogen-rich gas. And the continuous feed into the fuel cell is a hydrogen-rich

gas on one side and air that is coming from the top of the diagram on another side called the oxidant; so a fuel and an oxidant. These are the two feed stock really to the fuel cell.

The output of the fuel cell then is direct current power, which is shown to the right-hand side of the middle block, and heat and water. These are the by-product of the chemical reaction.

Now, the DC power, the direct current power, needs conversion and conditioning to become alternating current for use in most applications.

So, that in a nutshell is what a fuel cell is. It is a process to convert fuel directly into electricity. And there are five types of fuel cells that are defined or characterized in figure A-9. If we can flip to figure A-9, it gives us five types that we speak about in Exhibit 344 and the name of the fuel cell is the name of electrolyte, the material that is in between the oxidant and the fuel. The working material in between is called the electrolyte and it could be an alkaline fuel cell, a solid polymer fuel cell, but the three on the right-hand side are the ones we are going to focus on a bit more - phosphoric acid, molten carbonate and solid oxide. These three are the ones that we will describe with some detail in Exhibit

344 and take some time to describe to you.

Q. All right. And you mentioned that the cell is made of both the fuel and an oxidant.

What are the common fuels and oxidants?

A. The most common oxidant is air. Ideally, a fuel cell would work better on pure oxygen, but air is so much more convenient. That is the most common oxidant used.

In terms of fuel, again, ideally, the fuel cell would work best with pure hydrogen, but natural gas and light refined fuel oil are much more convenient and they are the typical fuels today for fuel cells.

The most attractive fuels today really are natural gas and naptha. They get reformed into hydrogen by that reformer that we showed on page A-8.

Q. Okay. Can you give us a brief overview of some of the characteristics of fuel cell types that you are talking about?

A. To help me do that, I would like to turn to page A-10. In there you will see the five types on the left-hand side.

The next column shows the operating temperature of the fuel cell and generally speaking, the alkaline and solid polymer are low temperature fuel

cells. The molten carbonate and solid oxide are what is known as a high temperature fuel cell. They operate at a temperature of 650 degrees C to 1,000 degrees C.

The efficiency of the fuel cell is typically 40 to perhaps up to 65 per cent, so it is a fairly high conversion efficiency; and that is one of the attractions of fuel cells, that they convert a large amount of the fuel energy into electricity directly.

Then the two columns after that show what the fuel and the oxidant are and show whether there is a need for fuel processing, and that column shows that fuel processing can either be external or can be direct within the fuel cell itself. The final column shows the status and the applications of various fuel cells.

To note here is the phosphoric acid one. The middle one is the most mature fuel cell technology in use today. The high temperature ones, the ones towards the bottom of the table, are still under development. They are not commercially available. And the two on top, the alkaline and solid polymer, are more suited to transportation and to space and submarine applications.

For that reason, we speak about the bottom three as suited to utility applications and we

will remember that phosphoric acid is the most advanced and the other two are under development.

Q. All right. Can you give us some idea of the extent to which fuel cells are being used for electricity generation?

A. They are not widely used by utilities at this time. They still find use in specialized applications, as I said, space program for example.

Notable application by utilities are in New York. New York City has a fuel cell plant and Tokyo had a fuel cell plant. They are really twin plants. One went to Tokyo and one went to New York City, 4.8 megawatts each of the phosphoric acid variety. Really they were exploring some of the advantages of fuel cells, that they are low pollution, low noise, can be situated easily in the middle of a large urban area that has difficulty in getting transmission access.

The Japanese are further developing their facility into a 11-megawatt size facility, so, Japan is pushing forward with further demonstration of the phosphoric acid fuel cell.

There are various small demonstration and research units all over the world in utilities and universities and so on.

Our Exhibit 344, figure 3-4-1 shows some of the key developments in fuel cells.

Q. What about experience in Canada?

A. Canadian experience is limited to small-size fuel cells, and by that, I mean, about 40 kilowatt size fuel cells. Hydro Quebec started working with them in the '70s. The National Research Council bought a unit in the late '70s or early '80s and that unit got shipped to British Columbia Hydro for testing and for learning how it works. It is now with Ontario Hydro out at our Kipling Research Laboratories in a mobile trailer and there is a picture of that in our exhibit.

The notable industrial firm working on fuel cells in Canada is called Ballard Systems, Ballard Power Systems, and it is working on a solid polymer fuel cell basically for transportation application. And, in fact, Ballard and the Ontario Ministry of Energy and Dow Chemical are jointly demonstrating a 5 kilowatt unit in Sarnia at this time. So that sums up the Canadian experience that we are aware of.

Q. Okay. I think you mentioned the urban areas, but what are the attractive features of fuel cells and how will they fit into a power system?

A. The fuel cells have attraction in

that they are -- we mentioned their high efficiency in converting the energy of the fuel. They are modular in their design and configuration, so they have flexibility in siting and in meeting power demand in a modular way. They are low in noise and pollution. The by-products of their combustion is really water and very low air emissions.

They have cogeneration potential. They can be used because of their siting flexibility, they can be put close to an application that would need heat and electricity together. So those are the attractions that people find about fuel cells.

Because of those characteristics, fuel cells can have a very wide range of application. They can be serving remote communities. They can serve an industrial or commercial customer on-site generation. You can envisage a hospital or a university or a shopping centre having a fuel cell that would supply both heating, hot water or space heating as well as electricity, so the cogeneration potential is attractive there. Or it can become electricity centralized or a decentralized generating plant. So really it can fit in many, many applications for electricity generation.

Q. Just as with the others, could you

summarize the performance and cost assumptions that you used in the study?

A. For costing purposes, we assumed a 20-year life for a fuel cell. We assumed that it will work in a base load capacity, an 80 per cent annual capacity factor, and the efficiency depends on the type somewhere between 35 and 55 per cent.

For costs, we assumed that in 1991, a fuel cell would cost $4,800 per kilowatt and we expect that to go down to $2,500 per kilowatt by the year 2000.

Q. Now, is that capital costs?

A. That is the capital cost.

Q. Yes.

A. We expect there will be high operating and maintenance costs associated with fuel cells, about $140 per kilowatt per year in 1991 and that perhaps can decline to $50 per kilowatt per year by the year 2000.

The fuel we assumed for costing purposes is natural gas, somewhere between 2 and 3 cents per kilowatthour. The details about cost components is in figures 3-10-1 to 3-10-3 in Exhibit 344.

Q. Okay. Now, you mentioned the developments and potential improvements, would you just

describe that you expect will enjoy this improvement?

A. Fuel cells will improve in cost and performance when materials -- it really is a material science kind of challenge. You have seen the operating temperatures to be up to 1,000 degrees C in a fairly hostile chemical environment. So finding materials that can be durable for long periods of time and compatible to the electrochemical process, that is a challenge facing the fuel cell industry.

There are some challenges to do with scaling up a small design to a large design for the utilities. There are challenges to do with simplifying the reformer technology, to use natural gas - make it into a hydrogen-rich fuel; that phase is critical to the success of fuel cells and there are challenges there.

We expect further demonstrations in the '90s. There are utility groups in consortiums exploring various options in the fuel cell industry and we can expect cost reductions and performance improvements in the late '90s.

Q. Okay. And for the purposes of your study, what fuel cell options did you pick?

A. We characterize two options; one that is 200 kilowatt size that would be appropriate to

envisage an industrial complex or a commercial institution or building, on-site natural gas fuel.

We also characterized a 10 megawatt utility option that would be similar to the one Japan is demonstrating at this time for a utility or large industrial scale application. It is also naturally gas fueled in our characterization.

Q. Okay. Those are the three you were going to speak to.

Mr. Dawson, would you just briefly describe the three alternative energy technologies that you are going to be dealing with?

MR. DAWSON: A. I am going to be presenting information on biomass peat and municipal solid waste. I would like to make the point that all three of those fuels essentially use the conventional steam cycle technology that I have talked about previously as the means of converting the energy and the fuel to electricity. The only differences are in the actual combustion processes itself.

[2:45 p.m.]

I think another point that's very important to recognize is that all three of those fuels essentially contain only about 15 per cent of the energy on a volumetric basis that is contained in a

bituminous coal, and on a weight base it amounts to about 35 per cent of the energy in coal.

The reason I stress is that is that it means that those fuels are expensive to transport, and, therefore, it tends to lead to systems where you have a small generating plant which is generally close to the fuel source to avoid transportation of the biomass peat or municipal solid waste.

Q. Let's start with biomass. What's included in the phrase "biomass"?

A. Well, biomass is essentially any plant material that can be used as a fuel. It's also, I think, one of the few technologies that has the potential to be scaled up and used at a larger scale without adding CO(2) to the atmospheric inventory of CO(2) because the plant material is continually growing and absorbing CO(2), too. So it's essentially a closed cycle.

Wood is the most prevalent form of biomass in Ontario, and I am going to focus on wood for the rest of my presentation.

Q. Then, are there any special facts we should know about how the wood fuel is going to be produced for this?

A. Yes. Wood is organic material, and

by that I mean that it's mainly carbon with some oxygen and some hydrogen chemically bonded to the carbon. The chemical analysis of wood is presented in the Alternative Energy Report. That's Exhibit 344, and it's figure 4-2-2.

It is low in both sulphur and ash, very low in both sulphur and ash, but the problem is that it does have a high moisture content, and typically when it is burned it is around a 50 per cent moisture level. As a result of that, the heating value tends to be relatively low, and it's around 11 megajoules per kilogram at a 50 per cent moisture content.

Q. How would that compare to coal?

A. It's about a third of the heating value of bituminous coal.

Q. What about wood availability?

A. It's available as a waste from lumber and the production of paper. Currently, about half of the wood waste is used in cogeneration applications, and that's largely at pulp and paper mills where it's used to produce process steam as well as in-house electrical generation quite often.

The Alternative Energy Review estimates that there is approximately 200 megawatts' worth of wood waste remaining that is unused. The difficulty is

that it's spread over a fairly large geographic area and it's in a large variety of forms, and as a result of that we believe that probably it is only practical to fully utilize maybe half of that. So we estimate 100 megawatts.

Q. What geographical area are we talking about?

A. I am talking about Ontario.

Significant new generation, therefore, must be based on new approaches, and there are some different approaches to providing wood as a fuel. It could come from selective forest thinning or from clear cutting of forests as is done for the pulp and paper industry. Again, those options are presented in figure 4-2-1 of the Alternative Energy Report.

The difficulty is that the costs of that approach are likely to be high, and therefore, the third alternative looks somewhat more attractive, and that is plantation cultivation of wood, specifically for electrical power generation, and that uses hybrid species of poplar or willow which are fast-growing.

Q. You have done a schematic in your Exhibit 473, D17?

A. Yes. That's the overhead that describes the production of plantation wood. It shows

the cycle from site preparation through to plantation of the seedlings, and then their growth.

I think the essential point to make is that willow particularly has its highest production period during its early years of growth, during the first three or four years, and, therefore, the idea is that you would harvest it after that initial high level of growth, and then what happens is that it produces small growth from the same root stock so that you continue to use the same root stock and harvest it every three or four years and therefore maximize the production rate of the wood fuel.

This looks promising, and it's estimated that it could cut the price of wood as a fuel down to maybe half by the year 2014, and at that point it would be relatively close to coal.

Q. And how much actual experience is there in this -- why do they call it "mini-rotation concept"?

A. Well, there are other approaches that use poplar, but there they tend to use a 10 year rotation cycle rather than the short three or four year rotation that is used with willow. Therefore, willow plantations have used this term "mini-rotation".

Q. What kind of experience exists?

A. There is no commercial experience with willow, and these estimates are based on experimental results.

There is some commercial experience with 10 year rotation of hybrid poplar, but this has a lower yield, and again, that information is presented in figure 4-2-1 of Exhibit 344.

Q. How much land are we are talking about for these plantations?

A. For a 15 megawatt generating plant, if we assumed it was going to operate at 80 per cent capacity factor and we further assumed that you were able to utilize 82 per cent of the land to produce wood, then you would need approximately 60 square kilometres to produce the wood fuel on a continuous basis over 30 years for a 15 megawatt plant.

Q. What is 60 square kilometres?

A. Well, essentially, it would be from the lake up to here, to Eglinton, and from Yonge Street across to the Humber River is roughly that sort of an area.

Q. Okay. That gives us an idea. I assume if you look at this concept, it's cut down when it's green. What happens then with respect to preparation after you have cut it down?

A. Once you have cut it down the moisture content in the wood as it's green is somewhat higher than 50 per cent, and you would ideally like to leave it out there to dry until you achieve at least 50 per cent moisture.

Then it would be collected and chipped to about a 5 by 5 by 1/2 centimetre size, and then it would be placed into temporary storage, and after that it would be taken to be burned.

There is one option, which would be that you could use flue gas from the back end of the boiler to dry the wood chips prior to firing, and that would essentially be an economic tradeoff that would have to be assessed at the time you were building the plant.

Q. How do you go about burning these wood chips?

A. Essentially, as I mentioned, the technology is conventional steam cycle, but there are a number of special technologies that are used to burn wood. And again, those are all presented in table 4-3-2 of Appendix B of Exhibit 344.

The spreader/stoker travelling grate is the most popular appropriate, primarily because it gives you good control over the steam supply, though fluidized bed combustion is gaining in popularity, and,

as I mentioned earlier in the discussion of coal combustion, it's particularly useful if you have got multi-fuel or you want multi-fuel capability.

Overhead D18 is a travelling grate stoker boiler, and unfortunately the hard copy comes out as being very much black and white.

Q. Where --

A. Again, the technology is very much the same as the boiler I described earlier when we were discussing coal combustion. The difference is that there is a grate in the bottom of the boiler which is used to support the wood fuel, and if you can think of it as essentially being a conveyor belt that travels across the bottom of the boiler and carries the wood fuel across as it burns so that it takes on wood at one end and discharges the ash at the other side of the boiler.

Spreader/stoker sizes, because of technical limitations, are limited to 75 megawatts in size or thereabouts, whereas fluidized bed boilers are currently being built at 150 megawatt scale, though they are slightly more expensive, we believe, on a dollars per kilowatt basis.

Q. What about control of emissions? What's involved in that?

A. This same overhead actually does show -- if you notice on the right-hand side of the diagram, it refers to a primary dust collector and a secondary collector which are cyclones, centrifugal devices, which separate the ash from the flue gas.

Q. On the overhead, those are the light blue sort of cones at the bottom?

A. That's right. On the right-hand side, yes.

Q. Okay.

A. And they are a centrifugal device which separates the ash from the flue gas.

In addition, often you will find a wet scrubber added after the cyclones to collect fine ash material.

Electrostatic precipitators are not an easy application, and that's because there is a lot of unburned carbon in the flue gas, and that's difficult to collect, though they have been used in some applications.

There is negligible sulphur dioxide. Therefore, you don't need a scrubber.

Perhaps the other thing I should mention is that quite often a wood fuel boiler will use natural gas as support fuel primarily to -- well, it improves

economies of scale and the requirement for steam is generally more than the available supply of wood so they produce all the steam they need in the one boiler and use wood as the supplementary fuel. But it also allows them to regulate the steam supply through the use of the gas.

Q. How much experience is there, that you are aware of, with respect to wood fuel generation?

A. Well, there is considerable worldwide experience and considerable experience in Ontario, too - largely in the Ontario pulp and paper industry, where, as I mentioned, wood waste and wood bark are burned generally in cogeneration applications.

An example would be Kirkland Lake where there is a 119 megawatt unit, and 17 megawatts of that generation are provided from wood and the balance, 102 megawatts, comes from gas.

There is a unit in Chapleau which is 7 megawatts, and that is fired entirely on wood.

And there are a number of other applications which are detailed on page 108 of the Alternative Energy Report.

Q. Can you just summarize for us the current research and development work that is going on?

A. Yes. There are two major thrusts:

one is to reduce the cost of the fuel, and the other one is aimed at improving the generation technology.

Maybe we can get a little bit into the specifics?

There is a lot of R&D effort going on on short rotation forestry, the plantation type approach that I have described, and there is work going on in Belgium, in Holland, Italy, France, Portugal and Spain. Also, in the U.S.A. there is a 500 hectare biomass plantation.

Q. 500 hectares is a pretty -- can you translate that into acres for us?

A. I can't translate -- a hectare is...

Q. 2-1/2 acres, something like that?

A. A tenth of a square kilometre, I believe.

Q. That doesn't help me a bit. [Laughter] Anyway, we have got another question. I think it's 2-1/2, so we are looking at 1,000 acres?

A. I think it is. You are right. That rings a bell, though I am not totally sure.

Q. It sure isn't 60 square kilometres.

A. Pardon?

Q. It sure isn't 60 square kilometres that you mentioned earlier.

A. The 500 hectares?

Q. Yes.

A. 500 hectares would be -- actually, I think it's 100 hectares in a square kilometre, so that is five square kilometres.

Q. All right. Okay.

A. In Sweden there is another 400 hectares which is dedicated to willow plantations which are being produced for energy production.

In Ontario, Domtar and the Ministry of Natural Resources have been engaged and are engaged in short rotation forestry research, and there there is a 2,000 hectare plantation producing poplar on a short rotation basis.

Q. What is short rotation compared to the --

A. That's the 10 year harvesting cycle as opposed to the four year harvesting cycle that we have been looking at for willow, and that's being used to produce high quality papers.

The development of high yield plantation concepts are of considerable interest to the pulp and paper industry as well as for energy.

In terms of research into improved methods of energy production, as I mentioned, fluidized

bed is starting to play a much larger role because it provides fuel flexibility and reduced nitrogen oxide emissions.

There is work going on to improve the cycle efficiency through gasification of wood, and that would allow the use of combined cycle.

The third area where work is going on is in the pyrolysis of wood, which essentially converts the wood to a liquid fuel oil, and that would therefore allow transportation of the energy at lower cost because you have now got it into a more energy intensive form.

Q. Okay. Can you tell us the kind of performance and cost information that you studied with respect to wood fuel?

A. Yes. Overhead D19 summarizes the performance information and the cost information. The upper table refers to performance, and there we looked at two plant sizes, a 15 megawatt unit and a 75 megawatt unit, both single unit stations. The net outputs from that would be 14 megawatts for the small unit and 70 megawatts for the larger unit.

We have assumed a 30 year life, and that's basically a judgment call, and that's perhaps to some degree tempered by the limited information on the

plantation concept so that we are not sure about the wood supply and what happens after that sort of period of time.

The thermal efficiencies, as you can see, are around 25 per cent, just under 25 per cent for the 75 megawatt unit.

The lower table presents the costs, and, as you can see, there is considerable economy of scale in moving from 15 megawatts to 75 megawatts.

The later capital costs simply reflects the difference in the initial capital investment. The OM&A, as you can see, for the 15 megawatt plant is significantly higher than for the 75, and that's as a result of the fact that essentially you need the same operating staff to operate the same components whether you are running 15 megawatts or 75.

The fuel is the final cost item, and there again, there is some small economy of scale there, and that is essentially in the fuel preparation side of the fuel cost rather than in the plantation cost itself.

Q. We will come to LUECs altogether at the end. Can we move on now to peat and first describe what it is and what there is in Ontario?

A. Yes. Peat is partially decomposed

plant material that is decomposed in a water saturated environment over a long period of time.

[3:06 p.m.]

Q. And in Ontario?

A. In Ontario, as you can see from overhead D20, there are a large quantity of peat deposits. In fact, if we were to utilize only 2 per cent of the peat deposits, that would allow us to support 5,000 megawatts of generation over a 30-year period.

There are areas in Ontario where the bogs are particularly extensive and you can see in Northwestern Ontario particularly, there are some very large peat deposits.

However, the difficulties are that it is a very dispersed resource and many of the bogs are either shallow or inaccessible.

There are also two types of peat and it essentially depends on the degree of decomposition that has taken place. I think we are all familiar with horticultural peat which is a mossy fibrous material that, in fact, hasn't proceeded very far in terms of decomposition.

And then fuel peat is in a more advanced stage of decay and, in fact, it is colloidal; and by

that, I mean that it exists as small particles dispersed in water and forms a gelatinous mixture.

Q. Okay. And then how do you go about recovering peat from a bog?

A. There are several approaches to this and they are described in chapter 5 of Exhibit 344. Probably the most popular one though is the milled peat approach which was developed in Finland many years ago, and that is the best developed and I think produces the lowest cost of fuel and I will describe how that process works in a minute.

Q. All right. How does peat compare to wood from a chemical point of view?

A. It is very similar to wood. Figure 4-2-7 of Exhibit 344 presents an analysis. The biggest difference is in the ash and the ash levels in peat are much higher than they are in wood and much more like the levels of ash found in coal.

It also has very high moisture content in the bog and it is typically about 90 per cent moisture and has to be dried down to about 50 per cent moisture before you can burn it, and that is typically done through air drying on the surface of the bog.

A 50-square kilometre bog which was 3 metres deep would support 75 megawatts of generation

over a 30-year period assuming an 80 per cent capacity factor. So, in fact, it is about five times more energy intensive in the deposit than a wood plantation would be, where we would get about 15 megawatts in that sort of an area.

Q. Okay. You mentioned the milling approach for peat recovery.

Can you describe that for us?

A. Yes. Essentially what happens is that the top two or three centimetres of the bog are loosened. This all take place after the bog has been drained by developing a dike arrangement to drain the water out of the bog; then it is able to support mobile equipment and the mobile equipment goes over the surface of the bog and loosens up the top 2 to 3 centimetres and then leaves it lying on the surface to air dry.

Once it has dried down to about 50 per cent moisture then a mobile vacuum cleaner comes along and picks it up from the surface and takes it away to storage and then you simply repeat that process again and you repeat it several times during the summer period when the weather is suitable to dry the peat.

One of the things you have to be careful with is that peat at 50 per cent per cent moisture can

spontaneously combust and, therefore, you have to be careful about the storage of the peat, make sure it is well compacted in the pile.

Q. Okay. Then would you describe the burning techniques? How is it burned?

A. Yes. Overhead D21 is a diagram of a suspension-fired boiler which was the technology that I described earlier for coal, and that type of combustion technology is needed for peat, because of the production method, it is in very fine, relatively fine particle sizes and, therefore, you have to burn it in suspension rather than on a grate.

The difference in this technology from that used with most coals is that it is advantageous to dry the peat prior to combustion and, therefore, we extract some of the flue gas from the boiler and divert that through the pulverizer which is going to grind the peat down to even finer sizes. And during that process, the peat is dried as well as ground and that is described in overhead D22.

Q. Just going back to D21 for a moment, I take it you use this for illustration because I see on the left it is called a raw coal bunker, I guess. We would stuff the peat in there if it were peat.

A. Right. Essentially, this technology

is used for brown coals that are burned in Germany, for instance, and it is the same sort of technology that is used for peat. So this diagram was probably originally used to illustrate brown coal combustion, but it is the same technology.

Q. Okay. Sorry I interrupted you. You were coming to the pulverizers?

A. Yes. A peat-fired or a brown coal-fired unit has a somewhat different pulverizer to that from a bituminous coal plant and that is shown in overhead D22. If we just look on the left-hand side of the picture, you can see a cross-section through the mill.

What it is, is essentially a rotating axle with a series of hammers attached to it and you can see that the clearance varies as it goes around the periphery of the mill. The peat is introduced in there with hot gas and it is essentially reduced in size by these hammers and then carried by the gas up through into the classifier which is the upper left-hand portion. And there, the fires are separated from any of the larger particles which are returned back down for further milling before being carried away to be burned in the boiler.

Q. And the boilers?

A. The boilers are much larger than they are for a bituminous coal. Again, it is a similar situation to that that we described before and it relates to the melting point of the ash. Peat tends to have low ash fusion temperatures and, therefore, the boiler would be typically 30 per cent larger than it would be for a bituminous coal and the cross-sectional area would be something over 50 per cent larger than it would be for the bituminous coal.

The other approach would be to use what is known as sub-peat or briquettes. If they were available, then you could use the grate burning technology that we described for wood fuel or again, fluidized bed technology is becoming popular and again provides fuel versatility.

Q. Okay. What about emission controls?

A. Again, the sulphur content of peat is low and, therefore, you don't need to use SO(2) scrubbers. Because of the high moisture content in the fuel and because you are burning it in suspension, we are able to limit the NOx emissions to similar levels to those for coal. We could also fit selective catalytic reduction if necessary to control NOx emissions.

We would certainly require particulate

control technology with this fuel because of the higher ash levels and there either a fabric filter or an electrostatic precipitator would be the device of choice.

Q. Okay. How much experience is there with peat fuel generation of electricity?

A. Most of the experience is in Finland and Ireland, though there is also some peat burning capability in Sweden and Russia, although we don't know much about the Russian experience.

In Ireland, there are approximately 500 megawatts of peat-fueled generation. And in Finland, there is about 600 megawatts and that is also, in a large number of cases, combined with cogeneration for process steam and district heating applications. Finland does have units that are up to 150 megawatts in size burning peat.

Q. Research and development work that is going on, what is taking place?

A. Again, the application of fluid bed combustion, and it is largely circulating fluid bed, is gaining ground and may well be more cost effective than suspension firing for peat because it would avoid the milling and the high temperature milling and that is an expensive proposition.

Gasification, again, should be an applicable technology and would help to improve the efficiency by allowing us to operate on a combined-cycle basis, but I am not aware of any work specifically that is going on in that area.

There is work going on looking at other mining techniques, such as mechanical mining where you would extract the peat as a slurry and then dewater it using filters, but I don't know that there is any practical work that has got beyond the study stage in that area.

Q. All right. The studies that were done in the review, what kind of performance and cost information do you use?

A. Overhead D24 again provides both the performance assumptions and the cost estimates for peat. Again, we selected the 15 megawatt and 75 megawatt single unit stations. This time, as I mentioned, it is suspension firing rather than grate firing technology and that does achieve a somewhat higher efficiency of about 26 per cent rather than just under 25 per cent for wood.

Again, the application has been assumed to be base loaded. Again, we have assumed a 30-year supply, again, largely because of the unknowns about

the resource rather than about the energy conversion technology.

Q. Okay.

A. The lower table shows the initial capital and I think the point to note is that it is significantly higher than that for wood burning technology, and that is largely because of the fact that we have beater mills and gas recirculation which is high temperature gas recirculation. That is expensive and it is also a significantly larger furnace because of the ash fouling difficulties that one would experience with peat.

Later capital and the OM&A are higher and they reflect the larger initial capital investment and the fuel cost themselves are, in fact, comparable to those of wood.

Q. Okay. Finally, let's deal with municipal solid waste. First of all, can you describe how it can be used as an energy source for generation of electricity?

A. Yes. There are two ways that municipal solid waste can be used: First of all, there is landfill gas and that can be used to drive a heat engine; or alternatively, the municipal solid waste itself can be burned and used to produce steam to drive

a steam turbine generator.

Q. Let's start with the landfill gas; could you describe that technology for us?

A. Yes. The landfill gas is derived from the decomposition of municipal solid waste in a landfill. It is typically about 50 per cent methane and the balance is generally carbon dioxide with some impurities. It's heating value is 17 megajoules per cubic metre and that is, as you might expect, about half the heating value of natural gas. One tonne of municipal solid waste would produce about 70 cubic metres of landfill gas. So, that equates to about 10 per cent of the energy in the municipal solid waste being recovered as energy.

Q. Okay. You mentioned it would be used to drive a heat engine. Could you give us a few more particulars of how it would be used?

A. Yes. It would be used in much the same way that natural gas can be used. It could be used to drive the reciprocating engines or gas turbines or, in fact, to fire a boiler. The application would depend to some degree on the quality and the impurities that are in the gas. Chlorine, for example, is something that I think you find in landfill gas. And because of that, probably boilers would be the most

tolerant application, but I think, in fact, reciprocating engines have also be driven by landfill gas. They may need a cleanup system to remove chlorine prior to using it.

Q. How does one go about recovering landfill gas?

A. Overhead D25 is a diagram showing a landfill gas recovery system. It is essentially a series of wells that are either driven into the landfill or, in fact, it can be built into the landfill as the landfill is constructed.

The wells are then interconnected with a piping system and a pumping system to deliver it to the generating station that would be located right at the landfill.

Q. Okay. How is it generated? It just doesn't all gush up at once.

A. No. Overhead D26, in fact, shows a typical production curve for landfill gas over time and you can see that, in fact, the production rate declines over time until after 25 years, it is less than 40 per cent of the initial production rate. That, of course, creates some problems for the developer in that he has to size the generation equipment to meet a variable flow.

So, what that probably boils down to is that in the early years, some gas is probably flared rather than being used for electrical generation because you would tend to size the generation equipment for something less than 100 per cent of the gas production in the early years.

Q. Okay. What experience exists with respect to landfill gas use?

A. There is an application in Ontario that is currently operating and that is a 22-1/2 megawatt facility that is located on the Brock Road landfill in Toronto. We expect that it would likely be 60 to 70 megawatts of installed capacity by about the year 2005.

Q. Okay. Now let's turn then to the actual municipal solid waste itself. Tell us about that as a source of energy.

A. Okay. Municipal solid waste is a non-homogeneous mixture of household and commercial waste. It is variable in energy content. The quantity available is very much dependent on the population density and on the current commercial activity within an area.

We need relatively large sources of refuse to make electricity generation worthwhile;

though rapidly escalating landfill fees that we have seen in the last few years are tending to reduce this as a criterion, it is beginning to look more economic for smaller and smaller amounts of refuse. It has a heating value that is the range of 9 to 11 megajoules per kilogram.

The opportunity to reuse some municipal solid waste and also the benefits provided by having a homogeneous fuel have lead to some development of some separation and recovery processes; for instance, processes that would remove metals and glass from the municipal solid waste prior to it being used as a fuel for energy generation. That has the benefit of increasing the heating value up to the 12 to 13 megajoule per kilogram range. And the fuel that is produced out of that sort of a process is generally referred to as refuse-derived fuel.

Much of the combustible fraction in municipal solid waste is biomass and is, therefore, renewable and, therefore, it has limited and small impact on the CO(2) inventory in the atmosphere, especially if you consider the fact that if it is landfilled, it also produces CO(2) which is emitted to the atmosphere anyway.

[3:28 p.m.]

Q. What about combustion technology? When I think of burning municipal solid waste I think of incinerators. This is something different?

A. Well, the combustion technology is essentially the same as that used in an incinerator, or it can be.

It is a type of travelling grate and, in fact, for refuse derived fuel we would use the same type of travelling grate that we talked about for wood fuel combustion. And again, that's described, as I think I said, in Appendix B of Exhibit 344.

An example of that type of application is the SWARU facility which is located in Hamilton.

Q. What does SWARU stand for, S-W-A-R-U?

A. I did use --

MR. SHALABY: A. Solid Waste Reduction Unit. With friends like you, Mr. Howard, I don't know why we need any cross-examination. [Laughter]

Q. Well, I just didn't do a good job before we got here. I am glad somebody is.

Solid Waste Reduction Unit in Hamilton, tell us about that.

MR. DAWSON: A. Well, the one in Hamilton actually produces very little generation, and that was the first generation of this technology and it

had all sorts of teething problems when it was first installed back in the '70s.

We are now into third generation designs, and, in fact, there is one operating, and I think operating quite well, in Massachusetts which produces 46 megawatts of generation using that process.

The mass burn technology is more like the incinerator that you referred to earlier, Mr. Howard. That technology is used extensively in Europe and Japan. There are a whole range of grate designs, and they are all designed to achieve a tumbling action of the refuse as it burns so that you burn the waste completely because it isn't shredded or prepared in any way prior to combustion. It is used extensively in Europe and Japan. It is also used in Canada and the U.S.A.

As I mentioned, the MSW is burned without any preparation other than there may be some shredding of very bulky items, such as furniture. That is illustrated in figure 6-3-2 of Exhibit 344.

One of the problems that you experience with that type of technology is water wall corrosion, and that is because of the chlorine content in the fuel and the variable nature of the fuel, and so typically the water walls are coated with refractory to protect

them from corrosion.

Q. What about emission controls?

A. Typically, on a modern design of either of these technologies you would include a lime spray dryer scrubber, as I described earlier for coal combustion technology. That would be followed by a fabric filter.

The spray dryer technology would remove anything that was condensable down to about 65 degrees celsius because that is the flue gas temperature leaving the spray dryer, and the fabric filter would do a highly efficient job of removing trace organics and metals as well as ash. And SO(2) and HCl, of course, are captured by the spray dryer.

Nitrogen oxide emissions will depend very much on the nitrogen content in the fuel, and that is difficult to predict, but you could use either your air injection or selective catalytic reduction to limit nitrogen oxide emissions, though there is no experience that I am aware of with either of these applications.

There is in the Thermal Cost Review in figure 6-4-5 and 6-4-7--

Q. I think you said Thermal Cost Review?

A. I'm sorry, I meant in the Alternative Energy Review.

Q. That's Exhibit 344?

A. Exhibit 344. --a comparison for the Victoria Hospital energy from waste facility, which is in London, and the SWARU facility in Hamilton, a comparison of their emissions against Ministry of Environment standards for various pollutants.

We should just bear in mind that the SWARU facility doesn't have a scrubber on it either, whereas the Victoria Hospital facility does, in fact, have a spray dryer and scrubber on the back end.

Q. How much experience is there in using municipal solid waste in electrical generation?

A. Figure D27 shows world experience, and, in fact, there are a total of 518 incinerators or energy from waste recovery systems, I should say, in the world, and this provides a distribution throughout the world.

It does not include Canada. There is a separate figure in the Alternative Energy Report, and that is figure 6-4-4, which shows that there are seven energy from waste recovery units in Canada which total 25 megawatts of electrical generation.

All but 40 of the 518 shown in this overhead are mass burn technology, and the remaining 40 use refuse derived fuel of one sort or another, and a

number of those would use travelling grate, stoker, combustion -- conversion technology.

I should add that in France they are shown to have 48 energy from waste facilities. Electricite de France, which is an electric utility, own and operate several mass burn facilities in the City of Paris and operate them both as electrical generation and cogeneration facilities for the City of Paris.

Q. Can you conclude the performance and cost alternatives that were used in the review?

A. Yes. That is presented in figure D28, and again, the upper table presents the performance information and the lower table presents the cost information.

The 50 megawatt mass burn facility would comprise three boilers, and they would burn -- each of them would burn 825 megagrams per day of municipal solid waste.

We have assumed state of the art emission control technology, which would include the spray dryer and fabric filter. There would be a single 50-megawatt steam turbine generator. The thermal efficiency is just under 20 per cent, and that would consume roughly about 30 per cent of Metro Toronto's daily garbage

production.

The lower table shows that the initial capital cost is high, and that is because you need extensive facilities to manage the truck traffic that is delivering the MSW to the plant, you also need a large storage facility, and the boiler itself is capital intensive. As well as that, you also have extensive emission control equipment on the back.

The later capital and OM&A costs are also high, and they acknowledge the severe corrosion potential that exists with municipal solid waste. I think the high point of this is that the fuel cost is negative, and that isn't shown in the table.

Of course, what actually happens is that the plant charges a tipping fee for disposal of municipal solid waste, so it generates a cash flow rather than being a cash outlay for the fuel. And Mr. Shalaby will be talking about the future application of this technology later.

MR. HOWARD: Mr. Chairman, we are now going to turn to looking at the environmental effects of these technologies and finally LUECs, and I think if we are going to take a break this afternoon I think this would be a good time. I think we will finish up handily by a quarter to five.

THE CHAIRMAN: Fair enough.

MR. HOWARD: I am not sure I want to talk to these gentlemen tonight after that crack, but perhaps we can ask them one question in cross-examination --

THE REGISTRAR: We will break for 15 minutes.

---Recess at 3:37 p.m.

---On resuming at 3:55 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Be seated, please.

MR. HOWARD: See if we can get through the rest of this without any undertakings.

Q. Dr. Effer, I would like you now to deal with the environmental effects of the six alternative energy technologies we have been discussing.

First of all, would you just give us an overview, an outline, of the effects of the six technologies?

DR. EFFER: A. The environmental effects of the total fuel cycle have been discussed in the Alternative Energy Review - that is Exhibit 344 - but I will be concentrating mostly on the electricity production effects.

However, some examples of possible impacts not related directly to generation are, for solar, the land use and aesthetic concerns that might be expressed with the amount of land being used, in addition to potential hazardous nature of some of the materials used in the manufacture of solar cells would require special handling facilities.

For wind, also the land area would possibly bring up concerns about land use and aesthetics.

With regard to fuel cells, the contents of the fuel cells would need special handling procedures.

For biomass, the loss of soil integrity associated with intensive use of fertilizers may be of concern, and also pesticides and herbicides which might be needed, as is often the case for monocultures, may need to be used, and they could become environmentally significant.

For peat, the harvesting of the fuel involves heavy equipment and construction of access roads over quite a large area, and these activities could impact the wildlife of the area and the hydrogeological regime.

For mass burning, that would have the

conventional impacts, such as odour, dust, noise and traffic disruption associated with delivering of the fuel to the power plant.

So, in summary, the non-generation impacts depend much on the technology used and may be managed in most case by known and accepted methods.

Q. All right. Then, could you relate these six alternative technologies to the six main issues that you have dealt with already in the fossil? Perhaps you could begin with photovoltaics?

A. Yes. I am possibly going to use the term "higher" and "lower", and these really define or compare those emissions of the technology that I am discussing, if you compared it with the fossil fuel combustion option with no spreaders and SCR controls.

For photovoltaics, emissions to air and water and production of solid waste are either non-existent or negligible, so operation of a photovoltaic facility would not contribute to any of the environmental issues in a significant way, and these are again acid rain, ozone, greenhouse effect, air toxics, discharges to water, and solid waste management.

Q. What about wind energy?

A. Again, emissions to air and water and

production of solid wastes are virtually negligible or non-existent.

Q. Fuel cells?

A. Assuming that natural gas is the fuel, there would be negligible or extremely low emissions of sulphur dioxide and nitrogen oxides, so there would only be a small contribution to acid rain and ozone production.

Higher plant efficiencies would also reduce the emission rate of carbon dioxides, therefore reducing its contribution to the greenhouse effect. There would be negligible air toxics emissions because of use of the natural gas.

If water were to be used in the steam cycle to reform hydrogen from the natural gas there would be small volumes of blowdown water and small amounts of emissions to water from the steam generator, but these would be very small, and extremely small volumes of spent catalyst would occur and also very small amounts of sulphur by-products.

Q. Then, can we deal with the plantation concept for biomass? How would that affect the six issues we have been talking about?

A. The overall effects on the acid rain issue would be lowered to approximately half the level

of sulphur dioxides emissions. Nitrogen oxides would be about comparable to the fossil fuel option.

Ozone production could be higher than for a conventional fossil-fueled plant if hydrocarbons are not controlled in the boiler and also if there are localized sources of volatile organic compounds, that there is a potential for ozone production. And again, as Mr. Dawson says, if necessary, there can be some kind of treatment, such as selective catalytic reduction for reduction of any nitrogen oxides.

Again, as Mr. Dawson said, the contribution to the greenhouse effect is about neutral because carbon dioxides taken up by the growing wood is released again to the atmosphere during its combustion. However, we can also consider that if the plantation biomass plant was replacing a fossil, a conventional fossil-fueled plant, then the carbon dioxide production could be considered negative. In other words, less CO(2) is produced than would normally be done with equivalent generation from fossil plant.

Organic toxics emissions with biomass could be higher, but without appropriate boiler design and operation lower trace element emissions would result with good particulate emission controls, such as cyclones and wet scrubbers.

Emission rates of heat and other discharges to water would be slightly higher due to the lower plant efficiencies.

Another source of contamination would be the drainage from the large wood pile and particularly the wood ash pile, which would need to be contained. However, wood ash would not be accumulating, I don't think, because it is a solid waste but it is high in minerals and could be recycled back onto the plantation to serve partly as a fertilizer.

Q. What about peat?

A. Acid rain or contribution of sulphur dioxide and nitrogen oxides to acid rain would be slightly reduced because the sulphur dioxide emissions are quite low and the nitrogen oxides are possibly similar to fossil fuel combustion.

Ozone production could occur due to the similar emission rates of nitrogen oxides, especially again if volatile organic carbon compounds are in the area.

A contribution of CO(2) emissions to the atmosphere would be slightly increased due to the lower plant efficiencies, and we are talking about emission rates here. Organic toxics emissions would need to be controlled by appropriate boiler design.

Trace elements production could be kept low by good particulate emission control, but I believe some elements - and I think this might be common for other things - such as mercury may not be contained too well.

Higher cooling water requirements and discharges to water would again be slightly higher due to the lower plant efficiencies.

Peat ash is present at about 10 times than in wood, so there is a large amount of ash produced, and this would possibly be a local source of contamination in the area. If that were important, then probably it would need to be contained to contain any uncontrolled releases of leachate.

[4:04 p.m.]

Q. Okay. And finally, what about municipal solid waste?

A. Well, firstly, with respect to landfill gas, which is burned to provide heat to the boiler, the contribution to acid rain would be approximately halved due to the lower sulphur content generally of the refuse. No. We are talking about the landfill gas here. The sulphur content of the landfill gas is low, but in the boiler, the emission rates of sulphur dioxides could be somewhat similar to

conventional fossil fuel generation, and for that reason, ozone production potential is similar.

For greenhouse gas contribution, the net effect of burning municipal solid waste is to greatly improve the situation because methane is a greenhouse gas which is approximately 30 times more effective as a greenhouse gas than carbon dioxide. So here we are exchanging one molecule of methane for one molecule of carbon dioxide and, therefore, the contribution to the greenhouse gases would be possibly reduced by over 95 per cent to 97 per cent.

In air, toxics emissions from the landfill gas combustion would be negligible and solid waste would be negligible.

With respect to the second type of MSW, the mass burn, as Mr. Dawson said, the content, sulphur content of the fuel is rather variable, but it generally would be lower than for conventional fossil fueled and the nitrogen oxides emissions could be similar to that of fossil fuel generation.

The ozone formation could be higher especially if volatile organic compounds emissions are not controlled by appropriate boiler design and operation. And again, carbon dioxide levels' emission rates would be slightly higher due to lower plant

efficiencies.

There is a high potential for production of air toxics. Emissions to air would have to be controlled by lime spray scrubbers, as Mr. Dawson has mentioned, and high efficiency baghouse filters would probably have been required.

Q. Again, water consumption and effluent discharge is slightly higher due to lower plant efficiency and there would certainly be needed to have containment and treatment of some of the water, the water that is used for quenching the hot ash product and also the drainage from the refuse pile would need to be contained.

The ash from the actual incineration itself would contain quite high levels of toxic elements and would require disposal in an engineered landfill site. An option there is to leach some of the elements out of the ash to provide a concentrated leachate and then dispose of the depleted ash in a regular landfill site.

And again, as Mr. Dawson said, one of the characteristics of municipal solid waste is the high content of chlorine in the flue gases derived from polyvinyl chloride and similar plastics in the municipal waste, but that would, of course, be removed

by the alkaline scrubber.

Q. Okay. Then can you come to some general conclusions about the environmental impacts on the six alternative technologies?

A. There are a number of general observations that can be made. With respect to emissions to air, photovoltaics, wind and fuel cells would have emission rates which are non-existent or generally much lower than a convention coal-burning plant. So, environmental and health effects via the atmospheric pathway would be considerably reduced.

On the other hand, at the other end of the concerns for these various alternative technologies, municipal solid waste would require very extensive pollution controls which you have just mentioned, such as wet and dry scrubbers, appropriate combustion conditions and containment of liquid wastes. These would be required to meet regulatory requirements on gaseous and solid waste.

With these emission controls and containments, we believe that environmental and health effects would then be somewhat comparable to a gas-burning or scrubbed coal facility.

With respect to water, existing technology will be able to control emissions to water

from the steam turbine and associated facilities. Effluents from the plantation biomass - that is the wood in the ash piles and the peat, that is peat itself and the peat ash pile - and the MSW mass burn would require bonding, special treatments and control releases to meet regulatory requirements. And also, we have mentioned the solid wastes; particularly the ash from the MSW mass burn would need to be contained in an engineered landfill site.

The operation of each of these alternative technologies with the possible exception of the MSW mass burn would tend to have lower impacts on human health than the conventional fossil-fueled option with no scrubbers or SCR.

MSW mass burn health impacts would also be lower with the appropriate controls on emissions and discharges to water and solid waste containment.

Briefly, going beyond the six environmental issues that I have been concerned with, we must note that some of these alternative technologies would have substantial environmental effects, other environmental effects than the six issues I have discussed; for example, wind, photovoltaics, peat, biomass have land use and visual impact concerns.

And I think Mr. Shalaby touched on this by saying that impacts of these technologies will change in degree and in kind, particularly on the public perception if one or more of these alternative energy options grows to become a significant proportion of the total system, and particularly we might consider aesthetics, the siting and land use and transmission impacts.

In summary, therefore, no technology is completely environmentally benign, although many of the alternative technologies do better than the fossil option in relation to the six main environmental issues. It should be mentioned, as I have just said, that they do have other adverse environmental effects.

Q. Okay. Thank you, Dr. Effer.

Can we come now to review the costs and your assessment of the potential of these alternatives of?

First of all, Mr. Shalaby, I would like to get the estimated costs from you. And how have you evaluated the costs for these alternative technologies?

MR. SHALABY: A. We relied on concepts that we described in Panel 3 on costing, so we have described some of the costs as a levelized unit energy cost and we described some options in a cost benefit

ratio. As you have seen in Panel 6, some of the hydraulic options were characterized by a cost benefit ratio.

For the dispatchable options which are fuel cells, peat and biomass, we would use levelized unit energy cost; for wind and solar, we will use cost benefit ratios; for municipal solid wastes, we will also use a cost benefit ratio to take into account the tipping fee part of the equation.

Q. When you say photovoltaics and solar, why do you use cost benefit ratios for those two?

A. Because the options are not dispatchable. You get the energy on an intermittent basis depending on the resource, so we would like to -- in addition to knowing what the costs of producing electricity from those sources are, we would like to characterize what the value of that electricity is. If it was at winter peak time, it has a different value than if it was at a summer peak or off-peak time.

In addition, we are providing two snapshots on costs. In some of the technologies, we expect major declines in cost. So for solar, wind and fuel cells, we are giving you a snapshot of costs today and in the year 2000, that we expect the major decline.

Q. Okay. Let's start with

photovoltaics; first of all, how did you go about costing the benefits of photovoltaic?

A. We calculate the energy benefit and the capacity benefit much like what we did in the examples we provided in Panel 3. You see what the energy production profile will be, what times of the year it will be producing energy and the length of production. We use a system incremental cost that we described in Panel 3.

We used the February 1991 vintage which is Exhibit 175 in these hearings. We assumed that solar energy has a capacity credit contribution to firm capacity of 20 per cent of its normal rating.

We provide a 10 per cent premium for renewable resource on solar power as we described in Panel 3. We assumed an in-service date of 2002 to make the cost comparison similar to what Mr. Meehan described for the fossil options and we give solar options and others an avoidance of transmission and distribution expenditures.

And perhaps here I would like to point out, too, what I think is an error in Exhibit 344. On page 34, there is a distribution credit of $10 per kilowatt and to the best of my knowledge, the calculations assumed $20 per kilowatt, not 10.

Q. So, that is a correction to Exhibit 344 which needs to be made on review?

A. Yes.

Q. All right. Then how do you go about calculating the photovoltaics for 1991 and 2000?

A. Well, if I may refer to page All in Exhibit 476, that has costs and benefit for the two photovoltaic options that we characterized. And for the purposes of following what is in it, perhaps we can focus on option 1 on the left-hand side of the table, which is the 2-kilowatt option. And under the option 1, we provide a snapshot assuming 1991 costs and another one assuming the year 2000 costs. Those are the two columns underneath the heading "option 1".

The first row would show the present value of the cost. And for example, in the year 2000, the present value of a 2-kilowatt cost would be $2800, $2.8 thousand in the first column and in the first row. Right below that is a present value of the benefits, and the benefits is $1.1 thousand in that case. Those are the two main ingredients shown in this table.

The next two quantities on the third and fourth row are derived from the first two quantities. On the third row, we see the net present value. The net present value is the cost minus the benefit.

So for the year 2000 cost, the net present value is minus 1.7, meaning the costs exceed the benefit by 1.7 and that means that the cost benefit ratio, which is 2.8 divided by 1.1, is 2.4. So, a cost benefit ratio higher than one indicates the option is not cost effective.

We are also providing levelized unit energy costs in cents per kilowatthour on the last row. And it shows that in the year 2000, option 1 would be 16.2 cents per kilowatthour.

There is an asterisk in there that says that LUEC may not be the only appropriate measure, again, to recognize that the option is non-dispatchable, but we think it is a useful piece of information to have in that table as well.

So that, in summary, is the cost benefit analysis for the photovoltaic options. We go through a comprehensive sensitivity analysis as well and that is documented in figures 1-10-7, -8 and -9 in the Exhibit 344, with assumed different life, different capacity factors and a different cost.

Q. Looking at these costs which you have been discussing, what conclusion do you draw with respect to the review that has been done on the solar options at this time?

A. I think combining the cost estimates and combining the environmental impacts that Dr. Effer spoke about, we see a continued use and, in fact, growth in the special niche applications that we have seen - communication, navigation, protection of pipelines and so on. That will be a growing area for the application of photovoltaics.

We see that the costs will decline considerably over the next ten years or so, but nevertheless, the costs even when they decline would remain two to three times what conventional sources would be.

There is potential nonetheless for manufacturing or a scientific breakthrough that can bring photovoltaic cost to become competitive with other options, but that is not seen to be -- again, by definition, a breakthrough is something that is non-predictable and we are not foreseeing that at this time. So, we see limited potential for grid connected electricity application.

We have defined for ourselves about three scenarios. We have asked the people who prepared Exhibit 344 to predict what the potential is for each technology and that was a hard question to ask and a hard question to answer because it is trying to

forecast what the market potential will be for a technology that is evolving quickly and reducing in cost.

They tried to assess the potential under three different conditions: One that would assume 1991 costs, no further improvement in costs; one that would assume a cost decline to the level of the 2000, the year 2000; and another one that is really undefined that says "more favourable conditions", cost reductions even beyond what we predict or societal acceptance beyond what we have assumed at this time, some break that will give the alternatives much more impetus.

And under those that range of scenarios, they expect little contribution under scenarios 1 and 2 but expect perhaps somewhere between 50 and 100 megawatts of photovoltaic grid connections dispersed throughout the system if favourable conditions exist, and it really is a ballpark estimate. There is no sort of detailed method of arriving at these things, just an estimate at that stage.

Q. Okay.

A. Figure 1-11-1 shows the details of that forecast potential in Exhibit 344.

Q. Okay. Can we come now to wind-generated electricity, benefits and costs?

A. A very similar methodology to do with energy benefits, capacity credit, transmission and distribution losses. And, again, a correction that the distribution is not $10; it is $20 for option 1, which is a small wind turbine, and zero dollars for the wind farm. The wind farm does not get distribution credits. The small option gets full distribution credit; 10 per cent premium in the evaluation.

And perhaps I can turn to page A12 to show the cost benefit analysis that we have conducted. It is very similar in format to page A11 for photovoltaics. The two options are shown side by side, 1991 costs as well as the year 2000 costs. And if we run through the numbers, we arrive at the cost benefit ratio of option 1 in the year 2000 of 1.5, which is a much closer number to one than photovoltaics.

[4:25 p.m.]

What we are indicating here is that wind is much closer to being viable than solar photovoltaics.

We are showing the levelized unit energy costs to be somewhere between eight and 10 cents per kilowatthour.

Q. Again, based on the analysis, what conclusions do you arrive at regarding the potential

for wind energy generation in Ontario?

A. For wind we also expect costs to decline in time and the margin between it and conventional sources to narrow.

We emphasize again that wind potential is very, very sensitive to identification of good sites, good wind regime, proximity to transmission, availability of the land for wind developments.

We think that if favourable conditions exist in terms of technology development, resource identification, perhaps up to 40 megawatts of wind farm developments could become a reality in Ontario in the long term. This is an estimate that is based on a study by Energy, Mines and Resources that was tabled in this hearing as Undertaking 322.13.

Right now the cost of wind exceeds other alternatives. The cost/benefit ratio is 1.7, as we see in A12, page A12.

So that is our projections for wind at this time.

Q. Now, can we turn to fuel cells, please?

A. The cost of fuel cells could be about 14 cents if we assume 1991 costs.

Q. You are looking at page --

A. Page A13?

Q. --A13, yes?

A. Yes. Page A13 shows the three technologies that we think are viable utility options and giving you a snapshot of 1991 and the year 2000 costs, and it's broken down into capital, OM&A and fuel. And then the final row shows a total levelized unit energy cost.

The top part of the figure is for the 200 kilowatt option, and the bottom is for the 10 megawatt option.

And the range of costs is somewhere between eight and 10 cents per kilowatthour in the year 2000 and about 14 cents in the year 1991.

Q. I hesitate to ask this, but what does the N/A stand for under "1991 Costs"?

A. Not available, in the sense of those technologies are not available in 1991. These are emerging technologies, and we expect them to be available to utilities in the year 2000.

Q. Then the 10 megawatt?

A. The 10 megawatt, similarly the costs are shown here. There are some economies of scale that -- you can see, for example, molten carbonate fuel cells to be producing electricity at 6.9 cents per

kilowatthour in the year 2000.

Q. Then, what conclusions do you draw regarding the potential for fuel cell in Ontario?

A. Well, the costs are still higher than conventional sources even in the year 2000, but the attractive features of fuel cells, such as capability of cogeneration, ease of siting and environmental -- the emissions are lower than other sources, would probably make fuel cells attractive in commercial applications such as hospitals, universities, large office buildings.

Natural gas costs will continue to be a major factor in the electricity costs of fuel cells. The potential could be high for fuel cells, and we estimate could be as high as 800 megawatts, if in fact it can be developed and packaged in a way that it will be acceptable in large institutions, shopping centres, that kind of...

And we have details of our expectations of potential in figure 3-10-11.

Q. Then what about biomass?

A. Turn the page to A14. You will see our levelized unit energy cost for the two biomass options that Mr. Dawson described.

If we go down to the bottom you will find

the levelized unit energy cost to be 13.7 for the 15 megawatt plant and 9.5 cents per kilowatthour for the 75 megawatt plant, and we have done sensitivity analysis varying assumptions, and the results of that sensitivity is displayed in figures 4-10-4 to 4-10-6.

Q. Then, what conclusions do you draw with respect to the potential for biomass technology in Ontario?

A. The conclusions we draw are in a big way influenced by what Dr. Effer observed about potential environmental considerations governing harvesting of biomass, land use, fertilizer use, and so on.

But the costs at this time are higher than other fossil potentials. The environmental impacts are really site-specific: what tract of land is to be developed, if we are going to the plantation kind of option.

We see that the waste, the use of waste wood is a viable option. It is in place already in Ontario in many places, and we expect that to continue to be a viable option, disposing of waste for electricity generation.

We don't see plantations dedicated solely for energy to be a likely occurrence in Ontario, but to

generate the potential that we came up with it is somewhere between 10 megawatts and 200 megawatts, depending on the extent of waste exploitation and the extent of plantations in the future. And those details are in Exhibit 344.

Q. Then, what about the cost of electricity from peat?

A. If we turn to page A15, you see a similar table to A14, but it is on peat, the two options Mr. Dawson described.

The cost for them ranges between 19 1/2 cents per kilowatthour for the 15 megawatt option and 12.2 cents per kilowatthour for the 75 megawatt option.

Again, we have done sensitivities and they are recorded in tables 5-10-4 to 5-10-6 at various assumptions to see what the levelized unit energy costs would be.

Q. And what is your conclusion with regard to the potential for peat in Ontario?

A. The costs are higher than fossil alternatives, higher than wood as well, but the potential in Ontario is really large.

Ontario has one of the largest peat deposits in the world. The environmental impacts are very site-specific. They depending on harvesting

technology, and the way things would be done, and where it would be done.

All in all, we see a small contribution possible from peat, perhaps up to a hundred megawatts into the future, and we have details of that potential in figure 5-11-1.

Q. And finally, municipal solid waste costs?

A. Page A16 shows a table of a little different format than we have seen before for municipal solid waste.

It shows the cost/benefit ratio and the other parameters as a function of tipping fee. Tipping fee, as Mr. Dawson indicated, is a very critical parameter to the economics of municipal solid waste and mass burn.

If tipping fees were high - that is the lefthand column of $150 on top of it - then the economics are quite favourable. You find a cost/benefit ratio of .3. If a tipping fee decreases down to 16, then to 30, then the cost/benefit ratio rises, and it becomes one at tipping fee of about $17 per ton.

So what that table tells us is that as long as tipping fees are higher than $17 we think that

mass burn is an economically viable operation in Ontario.

We did not produce a similar table for landfill gas. Landfill gas is much more site-specific, and although it is starting to see developments here in Ontario we at Hydro are not as familiar with landfill gas as we are with mass burn. And it is much more site-specific, as I say.

Q. So what general conclusions can you draw with respect to the potential of municipal solid waste in Ontario?

A. Municipal solid waste has a limited potential. It is really limited by the amount of garbage there is and the amount of landfill gas that there is. Panel 5 went into a lot of detail about the limitations and the quantities and the potential.

It is more viable in urban areas where there are collection systems that can have large amounts available for incineration. The costs depend very much on tipping fees, and generally the costs would be lower than other fossil options for tipping fees, above $17 per ton.

A notable thing about incineration or mass burn of garbage is that the government of Ontario has a ban on incineration at this time, so despite

favourable economics there are other factors that limit that option in the meantime.

The potential for energy from waste, solid waste, could be up to 225 megawatts in Ontario.

Q. I notice in that that you haven't produced any levelized unit energy costs. Why would that be?

A. To incorporate the tipping fee, we wanted to show how the benefits, present value of benefits, for electricity as well as for the operator of the municipal waste disposal facilities, those two combined.

Municipal solid waste facilities are mostly a disposal facility and only secondarily are they an electricity generation facility. It really is a waste management problem, more so than an electricity generation problem. So we feel that is a more appropriate way of presenting the cost.

Q. Then, just finally, Mr. Shalaby - you have been at it now for nearly two days - would you attempt to summarize for the Board the main points and conclusions which you would like to leave with them as a result of this evidence by the Fossil Panel?

A. In eight minutes. Is that right?

Q. You can take less.

A. A two-day job in eight minutes?

Q. Don't expand the job to fill the eight minutes. [Laughter]

A. I guess very quickly, we have shown what the environmental requirements are for fossil generation and for alternative technologies, and we have shown that if these environmental requirements are met, as in Dr. Effer's evidence, then the risk to the public of fossil plant operations become acceptable.

The project-specific environmental assessments that follow this stage in the hearings will characterize impacts more specific. So I guess the fuller impact of a fossil plant is better dealt with or more accurately dealt with in a specific situation in a project-specific, site-specific analysis.

But, in general, there are environmental requirements, and there are technologies that can meet those environmental requirements and render the facilities acceptable.

The second point we touched on is the life management, life extension of some of the existing fossil stations at Hydro.

As the 1992 Update indicated, that is now an option being explored by Hydro, and we have given evidence that we feel this is an option that has some

merit to be considered, and we have some evidence that some of our stations can last longer than initially indicated, and that option of life extension reduces the requirements for major new supply during the planning phase.

As Mr. Meehan indicated, it doesn't advance any date for facilities very much, but it increases -- it reduces the amount required over the 25 year period.

The third subject we addressed was new fossil options. We showed a range of new fossil options to use a variety of fuels from natural gas to oil to coal, and there are various conversion technologies with multi-coloured slides from Mr. Dawson describing their parts and how they work.

The characteristics of those options make them suited to meeting variable or various system requirements. Some are suited for base, some are suited for peaking duty. So there is flexibility in the range of fossil options to meet a variety of duties on the system.

Q. Could you comment just at that stage on the lead times required for the various options?

A. Some options can be put in place in a fairly short lead time - in our business short lead

time would be four or five years - such as combustion turbine units. Some would be a longer lead time, perhaps seven, eight or nine years, such as an IGCC or the conventional steam cycle units.

So depending on the complexity of the plant, it can range from a short to a medium lead time.

The next point that we discussed and we would like to leave with the Board is that alternative energy technologies, the six technologies that we described to you, have promise for the province of Ontario. They have promise for providing electricity.

At the moment, they are limited to niche applications and to limited market potential, but we expect the costs to decline in the future and the contribution to increase in the future.

The exact potential is really something that is very difficult to determine accurately. It will depend to a very large extent on technology development and on identification of good resources here in Ontario, particularly in the area of wind. It also would depend on government policies, for example, in the area of the ban on municipal solid waste incineration.

And finally, the choice of an implementation for fossil options would be made as

needed. We are not at this time requesting any approvals for fossil facilities, but we feel it is appropriate to keep those options open to Ontario and implement them as required.

So what Hydro will be doing is monitoring the development of these options, both the fossil and the alternative ones, stay in touch with the technology development and the resource development, and implement those technologies when needed.

MR. HOWARD: Thank you, Mr. Chairman. That is the evidence-in-chief.

Mr. Watson said he would ask one question if I really insisted, but I think I can probably survive without.

THE CHAIRMAN: Well, we may have some questions as well before we call on Mr. Watson.

So we will do that next, but we will do that tomorrow morning--

MR. HOWARD: Thank you, sir.

THE CHAIRMAN: --at 10:00. Just again, just to mention that we will stop tomorrow at 1:00; we will not sit tomorrow afternoon.

THE REGISTRAR: We will adjourned until 10:00 tomorrow morning.

MR. MONDROW: Excuse me, Mr. Chairman.

Mr. Chairman? Excuse me. I wonder if I might take the last minute? I know the Board is in a hurry to leave. I will just take a minute, if I could.

THE CHAIRMAN: Please be seated.

MR. MONDROW: Thank you. I should have jumped up a little quicker.

I would just like to file an exhibit, and it will only take one minute.

THE REGISTRAR: No. 477.

---EXHIBIT NO. 477: Package containing "Non-Utility Generation Report", dated February 7th, 1992, submitted by Mr. Mondrow, together with some newspaper items related thereto, as well as IPPSO's policy reaction to same.

THE CHAIRMAN: We can now adjourn, can we? 477.

THE REGISTRAR: 477.

THE CHAIRMAN: Do you want to speak to the exhibit?

MR. MONDROW: I have one sentence. It will take ten seconds.

In the last several weeks Ontario Hydro's NUG policy has gone through some dramatic changes, and IPPSO would just like to put some related information before the Board.

The package contains Hydro's statements,

some newspaper items related to those statements, and IPPSO's policy reaction to those statements.

Thank you for your indulgence.

MR. HOWARD: I suppose it is futile of me to resist the filing of newspaper reporting, Mr. Chairman, but nevertheless, I record my dismay.

THE CHAIRMAN: We have filed a lot of newspaper reports, and we have discussed it many times, and we have referred in the transcript to what evidentiary value we consider them to be.

MR. HOWARD: Thank you, sir.

MR. MONDROW: Thank you, sir.

THE REGISTRAR: This hearing is again adjourned until 10:00 tomorrow morning.

---Whereupon the hearing was adjourned at 4:47 p.m. to be reconvened at 10:00 a.m. on Wednesday, February 19th, 1992.

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